STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

F I L E D
12-22-06
02:32 PM

December 22, 2006

Agenda ID #6259
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 05-04-015

This is the proposed decision of Administrative Law Judge (ALJ) Charlotte F. TerKeurst, previously designated as principal hearing officer in this proceeding. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 10 days beforehand. When the RDM is held, there is a related ex parte communications prohibition period. (See Rule 8.2(c)(4).)

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's **Rules of Practice and Procedure** (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served o parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to ALJ TerKeurst at cft@cpuc.ca.gov. All parties must serve hard copies on the ALJ and the assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

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Attachment

Decision **PROPOSED DECISION OF ALJ TERKEURST (Mailed 12/22/2006)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project.	Application 05-04-015 (Filed April 11, 2005)

(See Attachment C for List of Appearances.)

OPINION GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

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OPINION GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

I. Summary

This decision grants a certificate of public convenience and necessity (CPCN) to Southern California Edison Company (SCE) to construct the Devers-Palo Verde No. 2 (DPV2) transmission line project. This project includes two major transmission lines. The first will be a second 500 kilovolt (kV) alternating current transmission line between southern Arizona near the Palo Verde nuclear generating plant, and SCE's existing Devers substation located in North Palm Springs in Riverside County, California. This Devers-Harquahala transmission line will be approximately 230 miles long, depending on final routing choices. Approximately 102 miles of this line will be located in Arizona and the remainder in California.

To allow the power to reach SCE's load centers, the Commission also authorizes SCE to construct the 41.6-mile Devers-Valley No. 2 transmission line, an alternative to the West of Devers portion of the DPV2 project proposed by SCE. Devers-Valley No. 2 will be a second 500 kV transmission line between the Devers substation and SCE's Valley substation located in the unincorporated community of Romoland in Riverside County.

The DPV2 project[1] will increase the transfer capability between southern California and Arizona by 1,200 megawatts (MW), providing greater access to

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[1] Because Devers-Valley No. 2 is an integral part of the system upgrades necessary to increase the transmission transfer capability between southern California and Arizona, we use the term "DPV2" to refer to the combined Devers-Harquahala and Devers-Valley No. 2 transmission lines.

sources of low-cost energy in the Southwest. Parties have provided convincing evidence that DPV2 will provide economic and other benefits to California ratepayers.

The Commission authorizes SCE to construct the Devers-Harquahala line from either the existing Harquahala Generating Company switchyard located approximately 49 miles west of Phoenix, Arizona, as proposed by SCE, or a new Harquahala Junction switchyard that would be constructed about five miles east of the Harquahala switchyard at the point where the existing Harquahala-Hassayampa transmission line and SCE's existing Devers-Palo Verde No. 1 (DPV1) transmission lines diverge. Because terminating DPV2 at Harquahala Junction is less costly and is the environmentally preferred alternative, we instruct SCE to pursue good-faith efforts to reach a commercially reasonable agreement and seek the additional authorizations needed for construction of Harquahala Junction. If Harquahala Junction does not receive the needed approvals in Arizona or is otherwise not feasible, SCE may terminate DPV2 at the Harquahala switchyard.

The route for DPV2 between the Harquahala area and the Devers substation will parallel the existing DPV1 route, except that it may diverge from DPV1 to eliminate or reduce impacts in the Alligator Rock Area of Critical Environmental Concern (ACEC)[2] in Riverside County. The Alligator Rock—North of Desert Center alternate route segment would avoid the Alligator Rock ACEC and is environmentally preferable to the proposed route paralleling DPV1

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[2] An ACEC is an area within the public lands managed by the United States Department of Interior, Bureau of Land Management (BLM) that BLM designates for protection of historic, cultural, scenic, fish and wildlife, or other identified resources.

through the ACEC. The proposed route segment through the ACEC and most of the North of Desert Center alternative are on federal land controlled by BLM. We authorize SCE to construct the North of Desert Center alternative if BLM authorizes this route. Otherwise, SCE may build DPV2 on a route segment through the Alligator Rock ACEC area that is acceptable to BLM, if the route segment received full consideration in the Final Environmental Impact Report/Environmental Impact Statement (EIR/EIS) or if it deviates from one of the reviewed segments solely within BLM land and BLM undertakes supplemental environmental review.

The Devers-Valley No. 2 transmission line will be constructed adjacent to SCE's existing Devers-Valley No. 1 transmission line and primarily within existing SCE easements. SCE initially proposed upgrades to approximately 48 miles of existing 230 kV transmission lines, which SCE called the West of Devers portion of the proposed project. However, we conclude that the West of Devers upgrades are not feasible and that the Devers-Valley No. 2 alternative is a viable and acceptable alternative.

The Commission also authorizes SCE to construct certain upgrades to other electrical transmission and telecommunications facilities related to the Devers-Harquahala and Devers-Valley No. 2 transmission lines.

We adopt a maximum cost[3] for DPV2 of $545,285,000in 2005 dollars, which is decreased by $24,080,000 if the Devers-Harquahala line is terminated at

[3] Pub. Util. Code § 1005.5(a) provides that "Whenever the commission issues to an electrical…corporation a certificate authorizing the new construction of any addition to or extension of the corporation's plant estimated to cost greater than fifty million dollars ($50,000,000), the commission shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility."

Harquahala Junction. The maximum authorized cost is increased by $8,282,000 if the Alligator Rock—North of Desert Center route segment is used.

The Final EIR/EIS for the DPV2 project, prepared jointly by the Commission pursuant to the California Environmental Quality Act (CEQA)[4] and BLM pursuant to the National Environmental Policy Act (NEPA), finds that the authorized project has several significant unmitigable environmental impacts. We adopt the mitigation measures SCE proposes (called "Applicant Proposed Measures") and additional mitigation measures recommended in the Final EIR/EIS, in order to reduce the environmental impacts to the extent feasible; however, some impacts will remain significant even after the implementation of mitigation. The approved mitigation measures are contained in Attachment A to this decision. The Commission also adopts the mitigation monitoring plan proposed in the Final EIR/EIS. SCE must comply with the adopted mitigation measures and mitigation monitoring plan as a condition of accepting its CPCN. We modify that the Final EIR/EIS in one respect and certify that it has been completed in compliance with CEQA.

Upon balancing the substantial economic, operational, and other benefits of the DPV2 project against the unavoidable environmental risks, we find that the DPV2 project should be approved, with the modifications and conditions contained in this decision. In Section VII, we include a statement of overriding considerations for the authorized DPV2 project, as required by CEQA.

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[4] Public Resources Code § 21000 *et seq.*

II. Background

A. Procedural History

SCE first submitted an application to construct a second transmission line between the Devers substation and the Palo Verde nuclear plant in 1985, and in Decision (D.) 88-12-030 the Commission granted a CPCN approving the DPV2 project as then proposed, conditioned upon submission of transmission service contracts associated with the project and other requirements. In 1997, the Commission granted SCE's request to abandon plans to construct the DPV2 project.

Beginning in 2003, the regional Southwest Transmission Expansion Planning (STEP) group evaluated a number of potential transmission upgrades. Through a consensus process, the group developed a general expansion plan that includes the DPV2 project. The Board of the California Independent System Operator (CAISO) approved the DPV2 project on February 24, 2005. On September 7, 2006, the CAISO Board approved the Harquahala Junction and Devers-Valley No. 2 modifications to the proposed project.

On April 11, 2005, SCE filed Application (A.) 05-04-015, its current application for a CPCN for the DPV2 project, accompanied by its Proponent's Environmental Assessment (PEA). The Commission opened Investigation (I.) 05-06-041 on June 30, 2005, to consider appropriate principles and methodologies for assessment of the economic benefits of proposed transmission projects, including DPV2, that are submitted for Commission approval. A joint prehearing conference was held in A.05-04-015 and I.05-06-041 on July 20, 2005. The assigned Commissioner issued a joint scoping memo for A.05-04-015 and I.05-06-041 on August 26, 2005. The scoping memo categorized this proceeding as ratesetting and stated that hearings were necessary. The scoping memo also provided that evidence regarding DPV2 would be received in two phases. Phase 1 in A.05-04-015 and I.05-06-041 received evidence regarding the economic methodology used to assess cost-effectiveness and DPV2-specific need issues. Phase 2, in A.05-04-015 only, addressed environmental, routing, updated cost estimates, and other issues related to DPV2.

As provided in a September 27, 2005 ruling by the Administrative Law Judge (ALJ), parties filed comments and reply comments on Phase 1 issues. An ALJ ruling dated October 28, 2005 provided further guidance regarding the scope of Phase 1 testimony and evidentiary hearings.

Three days of evidentiary hearings were held in Phase 1 on January 10-12, 2006. The following parties filed opening briefs in Phase 1: the CAISO, SCE, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Bay Area Municipal Transmission Group (BAMx),[5] and Global Energy Decisions, Inc. (Global Energy). All of these parties except BAMx also filed reply briefs. Following the receipt of late-filed exhibits and opening and reply briefs, Phase 1 was submitted on March 24, 2006.

Evidentiary hearings were held in Phase 2 on July 10, 2006. SCE and DRA filed opening briefs in Phase 2. SCE filed a reply brief. Following the receipt of late-filed exhibits[6] and opening and reply briefs, Phase 2 was

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[5] BAMx is an unincorporated association of publicly owned utilities located in the Greater Bay Area. Members include the City of Santa Clara, Alameda Power and Telecom, and City of Palo Alto Utilities.

[6] Consistent with an October 31, 2006 e-mail ruling by the ALJ, SCE's motion to submit late-filed Exhibit 43 is granted.

submitted on November 13, 2006. In opening briefs, no party requested final oral argument before the Commission, as allowed by the scoping memo.

A joint State-federal environmental analysis of the proposed DPV2 project has been undertaken pursuant to CEQA and NEPA. The Commission, as the State lead agency under CEQA, and BLM, as the federal lead agency under NEPA, retained outside consultants to conduct the environmental review. The Commission's Energy Division oversaw the consultants' work on behalf of the Commission.

In November 2005 and January 2006, the Commission's Energy Division and BLM staff held eight scoping meetings in California and Arizona to collect public input for the scope and content of the joint EIR/EIS and for alternatives and mitigation measures to consider. In addition, six consultation meetings were held with agencies and local jurisdictions to discuss the proposed project. A Scoping Report for the CEQA process was issued in December 2005 and an addendum to the Scoping Report was issued in February and March 2006. The draft EIR/EIS was issued on May 4, 2006. The Commission's Energy Division and BLM staff held six public workshops on the draft EIR/EIS and the ALJ held three public participation hearings in June and July, 2006. The Final EIR/EIS was published on October 25, 2006.[7]

On November 9, 2006, the Commission issued D.06-11-018 in I.05-06-041. In that decision, we adopted general principles and minimum requirements for economic evaluations of proposed transmission projects that

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7 As provided in an October 31, 2006 ALJ ruling, the three volumes of the draft EIR/EIS have been entered into the record in A.05-04-015 as Exhibits 35, 36, and 37. The three volumes of the Final EIR/EIS are Exhibits 40, 41, and 42.

may be submitted in CPCN proceedings. While we considered the methodologies parties used in their economic evaluations of DPV2 in D.06-11-018, we did not address the economic value of DPV2. In today's decision, we consider all of the relevant factors that affect the cost-effectiveness of DPV2. We assess the parties' economic evaluations of DPV2 on their merits, recognizing that our guidance adopted in D.06-11-018 was not available when the evaluations were prepared.

The DPV2 project would traverse State and federal land in California and Arizona. The Arizona Corporation Commission must issue a Certificate of Environmental Compatibility before SCE can construct the project. In addition, BLM must determine whether to grant a Right of Way Grant on BLM-administered land in California and Arizona. SCE will also be required to obtain permits from several other State, federal, and local jurisdictions, including a Compatibility Determination from the United States Fish and Wildlife Service (USFWS) regarding proposed construction through the Kofa National Wildlife Refuge (Kofa).

B. Scope of Proceeding

In its application, SCE asserts four justifications for the DPV2 project, which can be summarized as follows:

1. That DPV2 would be cost-effective for California electricity customers because it would allow for greater access to low-cost, surplus generation in Arizona.

2. That DPV2 would enhance competition among the generating companies that supply energy to California and would facilitate SCE's resource procurement approach approved in D.04-12-048.

3. That the additional transmission infrastructure provided by DPV2 would support and induce the development of future energy suppliers selling energy into the California energy market and that DPV2 would increase liquidity in the market and, thus, help mitigate market power.

4. That DPV2 would provide resource reliability benefits, flexibility in operating California's transmission grid, and additional import capacity that may be needed during unanticipated conditions.

In the scoping memo, the assigned Commissioner found that the scope of A.05-04-015 includes the following as to the proposed project using SCE's preferred route and configuration, alternative routes and configurations, the No Project alternative considered pursuant to CEQA requirements, and non-wires alternatives:

- Need for the project (Pub. Util. Code § 1001[8]) including, but not limited to, the four justifications submitted in SCE's application.

- Consideration of the following factors contained in § 1002:

  1) Community values;
  2) Recreational and park areas;
  3) Historical and aesthetic values; and
  4) Influence on the environment.

- Consideration, pursuant to General Order (GO) 131-D, of whether the project promotes the safety, health, comfort, and convenience of the public.

[8] All cites to code sections refer to the Public Utilities Code unless specified otherwise.

- Consideration, pursuant to GO 131-D, of measures to reduce the potential exposure to electric and magnetic fields (EMF) generated by the proposed facilities.

- Consideration, pursuant to CEQA, of significant effects of the project on the environment; alternatives to the project; the manner in which significant environmental effects can be mitigated or avoided; and whether economic, social, or other conditions make it infeasible to mitigate significant effects on the environment.

- How SCE would comply with § 625.

- Impacts on the transmission grid and other transmission users.

- Cost-effectiveness and cost allocation.

- Project costs.

- Specification of a "maximum cost determined to be reasonable and prudent" pursuant to § 1005.5(a).

III. Project Benefits

In this section, we address the economic and other benefits that parties attribute to DPV2, and compare those benefits to project costs. We conclude that DPV2 will provide significant economic benefits for CAISO ratepayers, and that it would also provide operational and other benefits. We find that potential alternatives to DPV2 are insufficient and are unable to provide the economic and other benefits of DPV2.

A. Economic Evaluation of DPV2

SCE, the CAISO, and DRA submitted economic evaluations of the proposed DPV2 project. Other parties made recommendations regarding the cost-effectiveness of DPV2 based on review of the submitted economic evaluations or commented on specific aspects of the methodologies employed in the economic evaluations.

1. Benefit Perspectives

SCE, the CAISO, and DRA evaluated the benefits of the proposed DPV2 transmission project by comparing estimates of total costs that would be incurred without the proposed project and total costs if the proposed project is built.

As described in D.06-11-018, the benefit perspective of CAISO-area ratepayers is of primary importance in the Commission's evaluation of a proposed transmission project, since it reflects the effects on customers of the utilities within our jurisdiction.[9] All three parties reported the net impact of the DPV2 project on CAISO ratepayers. The CAISO also presented benefit results for the entire Western Electricity Coordinating Council (WECC) region (the WECC or Societal perspective). SCE provided limited information regarding potential economic impacts in Arizona and the WECC region.

As noted in D.06-11-018, there are three general categories of costs or benefits arising from operation of a transmission project: (1) the change in total production costs, or energy benefits, (2) changes in other quantifiable economic benefits and costs not derived from production cost analyses, and (3) foreseeable project consequences whose expected economic effects cannot be monetized. We address these three types of costs and benefits with respect to DPV2 in Sections

[9] As noted in D.06-11-018, while CAISO ratepayers include some non-jurisdictional entities, consideration of all CAISO ratepayers is an analytical convenience with minor effects on the economic evaluation.

III.A.3, III.A.4, and III.B, respectively. We evaluate construction and operational costs of DPV2 in Section III.A.5.

The energy benefits due to a transmission project consist of the net changes in consumer costs (consumer surplus), producer net income (producer surplus), and congestion revenues flowing to transmission owners or holders of transmission rights (transmission surplus). Since the Societal WECC-wide perspective represents a largely closed system with few imports or exports, the Societal benefit computed as the DPV2-caused net WECC-wide change in consumer surplus, producer surplus, and congestion revenues closely approximates the overall change in energy production costs due to operation of DPV2.

Energy benefits from the CAISO Ratepayer perspective are the net result of the increase in consumer surplus and changes in the utility-retained generation producer surplus and the Participating Transmission Owner (PTO) congestion revenues in the CAISO area. The producer surplus and congestion revenues received by CAISO-area utilities ultimately benefit CAISO-area consumers, because the utilities' generation and congestion revenues reduce revenues that would otherwise be sought from consumers to cover costs.

In D.06-11-018, the Commission declined to adopt a threshold benefit-cost ratio or payback period that a transmission project proposed for its economic benefits would be required to achieve in order to be granted a CPCN. As we explained in that decision, transmission projects such as DPV2 may have other benefits and costs in addition to those that can be quantified in a benefit-cost ratio. In Sections III.D and VII, we consider and weigh all relevant factors, including environmental impacts, in reaching a decision on SCE's CPCN request.

2. Overview of Parties' Economic Evaluations of DPV2

a) SCE

The results of SCE's economic evaluation of DPV2, as contained in its PEA and Exhibit 6, are summarized in Table 1. To allow comparison of DPV2 costs and benefits, SCE calculated the 2005 present value of DPV2 revenue requirements using SCE's fixed charge rate model and discounting at an assumed 10.5% marginal cost of capital. SCE projects that DPV2 will provide benefits to CAISO ratepayers of almost $460 million in excess of its costs, with a resulting benefit-cost ratio of 1.71.

Table 1

SCE's Economic Evaluation of DPV2
Proponent's Environmental Assessment

(CAISO Ratepayer Perspective)
(Net Present Value, $2005 Million)

Energy benefits	$ 1,063.3
Increased transmission revenues	$ 28.4
Reduction in franchise fees and uncollectibles	$ 13.0
Total benefits	$ 1,104.7
DPV2 costs	$ 645.6
Benefit-cost ratio	1.71

In addition to energy benefits, SCE reports that CAISO-area transmission owner revenues will increase due to the DPV2-caused increase in revenue requirements, which would increase rates for CAISO wheeling service and Existing Transmission Contracts. SCE also includes the effect of DPV2-caused reductions in energy costs on revenues needed for franchise fees and uncollectibles.

An earlier economic evaluation of DPV2 that SCE submitted to the CAISO on March 17, 2005 contained more detail than the economic evaluation submitted in the PEA. As summarized in Table 2, the March 17, 2005 study provided disaggregated CAISO Ratepayer benefits, which indicate the extent to which SCE forecasts that utility-retained generation and PTO congestion revenues would decrease as a result of DPV2's operation.

Table 2

SCE's Evaluation of DPV2 Energy Benefits
March 17, 2005 Report to CAISO

(CAISO Ratepayer Perspective)
(Net Present Value, $2005 Million)

Consumer surplus	$ 1,850
URG producer surplus	($ 685)
PTO congestion revenue	($ 96)
Net energy benefits	$ 1,069

In its March 17, 2005 economic evaluation, SCE modeled DPV2 operation for the years 2009 through 2014, and reported energy results for those years from the WECC-wide or Societal perspective and the perspective of Arizona customers, in addition to the CAISO Ratepayer perspective. With the assumptions underlying SCE's evaluation, the results in Table 3 indicate that Arizona customers would not benefit from DPV2 during the modeled years.

SCE did not report lifecycle benefit-cost ratios from these additional perspectives. We address these impacts further in Section III.D.

Table 3

SCE's Evaluation of DPV2 Yearly Energy Benefits

March 17, 2005 Report to CAISO

($2004 Million)

	WECC (Societal)	CAISO Ratepayers	Arizona
2009 (6 months)	$ 11	$ 45	($ 7)
2010	21	87	(11)
2011	21	92	(11)
2012	21	89	(12)
2013	26	118	(16)
2014	25	111	(17)

SCE forecasted DPV2's impact on energy costs using the Global Energy (formerly Henwood) production cost model using a "transportation" power flow simulation. In a transportation model, generator and load locations are aggregated into zones, and power is simulated to flow along contract paths between the zones, with each path potentially representing multiple transmission lines. Flows between zones are restricted by modeler-specified limits and do not reflect the effects of loop flow. A transportation model calculates prices on a zone-wide basis.

SCE used a stochastic approach to assess DPV2's energy benefits over a wide range of load forecasts, natural gas prices, and available hydroelectric generation. SCE assigned probability distributions to these key factors, based on documented historical variations, and simulated system operations under 100 different combinations of future conditions based on values chosen from the probability distributions using Monte Carlo (random sampling) techniques. SCE then calculated energy benefits as the probability-weighted expected value of benefits based on results of the 100 system simulations.

SCE calculated electricity prices and resulting consumer and producer surpluses based on projected spot market prices equal to marginal costs in each modeled zone. SCE did not reflect that, in some market conditions, generators may be able to sell power at prices in excess of marginal costs, i.e., that they may successfully mark up their bids above marginal costs and receive higher revenues in an exercise of market power.

b) CAISO

The results of the CAISO's economic evaluation of DPV2 are summarized in Table 4. The CAISO finds DPV2 to be cost-effective, with the CAISO Ratepayer benefit-cost ratio likely to be in the range between 1.25 and 3.34. This range arises because of uncertainty regarding congestion revenues between the CAISO control area, with its planned market redesign based on locational marginal prices (LMP), and Arizona,.

Table 4

CAISO Economic Evaluation of DPV2

(Levelized Annual $2008 Million/Year)

	Societal Perspective	Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP + Contract Path)
Levelized Benefits:				
Energy	$ 56	$ 84	$ 57	$ 198
Operational	20	20	20	20
Capacity	12	12	6	6
System Loss	2	2	1	1
Emissions	1	1	1	1
Total Benefits	$ 91	$ 119	$ 84	$ 225
Levelized Costs	$ 67	$ 67	$ 67	$ 67
Benefit-Cost Ratio	1.35	1.77	1.25	3.34

As indicated in Table 4, the CAISO presents economic results for two versions of the Societal perspective and two versions of the CAISO Ratepayer perspective. Unlike SCE and DRA, the CAISO forecasts the extent to which producers may exercise market power to bid up prices above system marginal costs. The two versions of the Societal perspective differ in their treatment of the effects of DPV2 in mitigating the ability of generators to exert market power. In the CAISO's basic Societal perspective, the reduction in market power-derived producer profits that the CAISO forecasts due to DPV2 is viewed as a negative benefit and offsets much of the projected consumer benefits from reduced energy costs. What the CAISO calls the Modified Societal perspective does not consider that portion of producer surplus arising from the exercise of market power to be a valid benefit and, thus, reflects the related increase in consumer surplus as a benefit. Because of the societal value in reducing producer monopoly profits, we determined in D.06-11-018 that, for evaluations that include strategic bidding above system marginal costs, the Modified Societal perspective, rather than the CAISO's Societal perspective, is the appropriate perspective to use in evaluating the societal benefits of a proposed transmission project.

To evaluate potential energy benefits of DPV2, the CAISO used the PLEXOS Direct Current Optimal Power Flow network model. A network model simulates electrical flows on individual transmission lines based on electrical principles and line characteristics, and models loop flow. Such a model optimizes the dispatch of generators to provide least-cost supply and permits calculation of LMP, consistent with the CAISO market redesign planned for the end of 2007.

The CAISO based its calculations for what it calls the CAISO Ratepayer (LMP Only) test on the modeling assumption that an LMP-based market structure would be applicable throughout the WECC. However, most of WECC employs contract-path scheduling, with no plans to implement an LMP-based market structure. The CAISO acknowledges that, as a result, its CAISO Ratepayer (LMP Only) calculation overestimates the loss of congestion revenue due to DPV2 and thus underestimates CAISO ratepayer benefits.

Because of the inaccuracy in its modeling of WECC-wide operations, the CAISO also reports an adjusted CAISO Ratepayer (LMP + Contract Path) benefit perspective. This adjusted calculation excludes much of the congestion revenues between southern California and the Southwest indicated by the CAISO's LMP-based modeling. This exclusion results in substantially lower pre-DPV2 revenues, and consequently a much lower negative benefit in the form of reduced congestion revenues when DPV2 is added. Recognizing some shortcomings to this adjustment as well, the CAISO believes that "the true answer lies somewhere between the CAISO benefits computed with and without this adjustment."

The CAISO developed low, medium, and high forecasts for load growth, hydro conditions, gas prices, and the degree of market power exhibited in producers' bids. To analyze the effects of uncertainty on the energy benefits of DPV2, the CAISO performed system simulations for 17 representative (out of 81 possible) combinations of the identified variations in these market conditions. It assigned probabilities to each of the 17 scenarios and used the results to calculate probability-weighted benefit-cost ratios. The CAISO also analyzed energy benefits for eight contingency scenarios representing certain outages and other contingency events, for which it did not assign probabilities and whose results it did not include in the calculated benefit-cost ratios.

In addition to energy benefits, the CAISO quantifies and includes in the reported benefit-cost ratios several non-energy benefits of the DPV2 upgrade as indicated in Table 4, principally operational benefits and capacity value. The CAISO assumes that the annual benefits for each of these areas of non-energy savings would not change over time in real terms and would not depend on market conditions such as demand, gas prices, or hydro conditions.

c) DRA

DRA's economic evaluation of DPV2, prepared with the assistance of its consultants including Woodruff Expert Services (WES), is summarized in Table 5. DRA forecasts that, with two sets of adjustments to SCE's base case analysis, DPV2 will provide net energy benefits of $261 million in excess of DPV2's costs, with a CAISO Ratepayer benefit-cost ratio of 1.31.

Table 5

DRA Economic Evaluation of DPV2

(CAISO Ratepayer Perspective)
(Net Present Value, $2005 Million)

	Deterministic Reference Case	WES Reference Case
Energy benefits	$ 595	$ 907
DPV2 costs	$ 646	$ 646
Benefit-cost ratio	0.92	1.31

DRA used the same system model and database used by SCE. DRA reviewed SCE's economic evaluation of DPV2, but did not address the

CAISO evaluation in its testimony.[10] DRA critiques several methods and assumptions used by SCE, describing some that underestimated and others that overestimated the value of DPV2. To address some of these concerns, DRA prepared a two-step analysis. First, DRA prepared what it called a Deterministic Reference Case, which used SCE's base forecasts for loads, gas prices, and hydro conditions but changed certain modeling conventions. As the second step, DRA updated SCE's gas price forecast to the higher forecast current at the time of DRA's assessment. DRA calls this deterministic simulation the WES Reference Case.

DRA considered uncertainty by evaluating eight sensitivity and contingency cases involving extreme outage events or alternative assumptions regarding gas prices and supply conditions. To assess the impact of forecast risk on the estimated value of DPV2, DRA used what it called an Uncertainty Margin method to conclude that the level of forecast risk can be relatively high without jeopardizing the conclusion that DPV2 is likely to provide net benefits.

DRA also undertook what it calls a tipping point analysis to identify which parameters, assumptions, or relationships drive the conclusions of its economic evaluation of DPV2. It identified four variables as tipping points: modeling conventions, the natural gas price differential between Arizona and California, the on-line status of the Palo Verde nuclear units, and the wholesale cost of natural gas. DRA calculates that, in order for DPV2 to be cost-effective, the wholesale Topock (Arizona) gas price must exceed $5 per million British

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10 On January 3, 2006, SCE and DRA submitted a joint recommendation in which, among other things, they recommended that the Commission find that DPV2 is needed based on its cost-effectiveness, and SCE withdrew its Phase 1 rebuttal testimony.

thermal units (mmBtu), the gas price differential between Arizona and California must exceed $0.50 per mmBtu, and Palo Verde must operate. Alternatively, DRA finds that DPV2 would be cost-effective if gas prices exceed $6.40 per mmBtu, even if there is no California-Arizona price differential.

DRA cautions that the WES Reference Case, while providing DRA's best estimate of DPV2's value, is limited by several identified uncertainties that could be better quantified, but only with significant additional effort. DRA is also concerned that some important uncertainties regarding modeling methods and assumptions may not have been identified, and cautions further that paradigm shifts in the energy market could render the DPV2 project uneconomic.

d) Other Parties

TURN presented testimony in Phase 1 that primarily addressed economic methodology issues that we have resolved in D.06-11-018. In its opening brief in Phase 1, TURN states that it agrees with SCE, the CAISO, and DRA that the proposed DPV2 project is likely to be a cost-effective investment for CAISO ratepayers. TURN finds comfort in the fact that DPV2 economics underwent substantial review by different parties using different methods and all concluded that DPV2 would be beneficial.

PG&E, SDG&E, Global Energy, and BAMx made recommendations in Phase 1 regarding the methodology to be used for economic evaluations of transmission projects. However, none of these parties took a position on the cost-effectiveness of DPV2.

3. DPV2 Energy Benefits

In this section, we address several areas of concern regarding the parties' economic evaluations of DPV2. We also describe the CAISO's and

DRA's examination of several unlikely but potentially significant contingency scenarios.

a) System Modeling

As we discussed in D.06-11-018, while the CAISO's view is that only network models provide an acceptable level of accuracy, both the network and transportation approaches as employed in evaluating DPV2 have strengths and weaknesses.

A network model such as the CAISO used in its DPV2 evaluation may provide more accurate forecasts of physical flows and locational prices in an LMP market and may identify the resulting congestion and its economic implications with more accuracy compared to a transportation model. However, because most of WECC outside of California uses contract path scheduling, the CAISO makes an "LMP + Contract Path" adjustment to approximate the market paradigm between the Southwest and southern California. While this adjustment has some similarities to SCE's and DRA's contract path approach, the CAISO still forecasts generator dispatch and power flows based on its network simulation. The "LMP + Contract Path" adjustment is, as the CAISO acknowledges, a simple approximation.

The CAISO's "LMP + Contract Path" measure of DPV2 energy benefits to CAISO ratepayers is over three times as large as that derived in the "LMP Only" calculation, as indicated in Table 4 above. As the CAISO suggests, the actual benefits may fall somewhere in this range. Thus, the potentially greater accuracy of the CAISO's detailed modeling of power flows appears to be overshadowed by the degree of imprecision in its calculation and allocation of congestion costs between Arizona and southern California.

In comparison to a network model, a simpler transportation model such as SCE and DRA used is computationally faster and allows a more complex analysis of uncertainty. A transportation model generally can permit more sophisticated modeling of generator operation. Despite CAISO concerns, SCE and other parties assert that, with care, a transportation model may be calibrated and validated regarding the effects of power flow complexities such as loop flow on system dispatch, prices, and congestion costs.

SCE describes that it established transfer limits on modeled interzonal transmission paths between Arizona and southern California to approximate how real world power flows on these paths would be limited. SCE used a Southern California Import Transmission nomogram, which quantifies the aggregate allowable electricity flows on the paths into southern California, depending on the amount of generating capacity operating in southern California and the status of the Palo Verde nuclear units. SCE described that, in addition to transportation modeling, it used separate power flow analyses to demonstrate the physical feasibility of DPV2 operation.

It is not possible to determine, based on the record before us, the extent to which modeling differences affected the parties' results. None of the parties benchmarked their modeling efforts to historical experience. Further, the CAISO and SCE/DRA evaluations used different input databases and simulated different market scenarios. The CAISO used a database developed by the Seams Steering Group—Western Interconnection (SSG-WI) with modifications to reflect SCE's system more accurately, whereas SCE and DRA used a database developed by SCE based on its recent procurement plans. While the CAISO and DRA reported inputs and results for each of the scenarios they simulated, SCE presented only expected value results obtained from its probability-weighted aggregation of the 100 simulations it undertook.

The most useful comparison available in the record that illuminates the effects of modeling differences is for the year 2013, which all parties modeled. SCE's stochastic results, DRA's Deterministic Reference Case, and the CAISO's "medium conditions and no bid markup" base case are roughly comparable. The resulting 2013 energy benefits from the CAISO Ratepayer perspective are summarized in Table 6. The fact that the energy benefits found by DRA fall almost exactly at the midpoint of the CAISO's "LMP Only" and "LMP + Contract Path" range of benefits supports the CAISO's view that market results will lie somewhere between its two estimates. Because SCE's stochastic process captures the higher value of DPV2 under extreme market conditions, we would expect the energy benefits reported by SCE to be significantly larger than the energy benefits that DRA found using base case conditions. The results summarized in Table 6 are consistent with this expectation.

Table 6

DPV2 Energy Benefits in 2013

(CAISO Ratepayer Perspective)
($2013 Million)

SCE stochastic results	$ 146
CAISO base conditions:	
LMP Only	$ 40
LMP + Contract Path	$ 137

DRA Deterministic Reference Case	$ 88

As TURN suggested, this limited illumination of differences in the parties' production cost modeling efforts confirms that there is value in having both network and transportation models employed in evaluating DPV2. The fact that the relationships among the energy benefits found by the parties are logical provides some assurance both that the CAISO's "LMP Only" and "LMP + Contract Path" estimates bracket actual energy benefits and that the more simplistic modeling underlying the SCE and DRA analyses may be reasonably reliable. We have greater confidence in the results of the parties' evaluations because SCE, CAISO, and DRA modeling efforts produce consistent estimates of energy benefits.

b) Natural Gas Price Forecasts

Both the overall level of natural gas prices and the California-Arizona differential in delivered gas prices affect the level of DPV2 energy benefits. Additionally, the relative efficiencies of power plants in California and elsewhere will influence the extent to which out-of-state gas generation may displace California generation. The gas price level matters because, if gas-fired generators in Arizona have an efficiency (heat rate) advantage over those in California, the higher fuel efficiency will yield greater economic savings when fuel prices are high. Also, the greater the California-Arizona differential in delivered gas prices, the larger the energy savings will be.

Natural gas price forecasts for 2013 utilized or reported in this proceeding are summarized in Table 7.

Table 7

Natural Gas Price Forecasts

($/mmBtu in 2013)

Source	Vintage	Arizona (Topock)	Southern California	California-Arizona Differential
CAISO DPV2 evaluation	Aug. 2004	$ 5.71	$ 6.08	$ 0.37
SCE DPV2 evaluation (Global Insight)	Oct. 2004	$ 5.27	$ 5.66	$ 0.39
SCE Global Insight gas price update	Oct. 2005	$ 6.26	$ 6.72	$ 0.46
DRA DPV2 evaluation (WES Reference Case)	Nov. 2005	$ 7.23	$ 7.62	$ 0.39
DRA gas price update	Jan. 2006	$ 9.53	—	—

In the system simulations undertaken by the CAISO, variations in gas prices had a greater effect on DPV2 energy benefits than any other market condition considered. The CAISO used a base-case natural gas price forecast published by the California Energy Commission (CEC), and developed "very low" and "very high" forecasts representing the lower 5% and upper 95% confidence levels. The effect of these gas price variations on DPV2 energy benefits is shown in Table 8, for base-case load forecasts and hydro conditions. As expected, the effect of gas prices on DPV2 benefits is not symmetrical, with high gas prices having a greater effect on DPV2 benefits than would low gas prices.

Table 8

CAISO Evaluations of DPV2 Energy Benefits
with Varying Levels of Natural Gas Prices
(Base-case Load Forecasts and Hydro Conditions, No Market Power)

($ Million Nominal)

	Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP + Contract Path)
2008 benefits:			
Low gas prices	$ 6.76	($ 2.41)	$ 17.07
Base gas prices	42.83	19.81	70.83
High gas prices	85.81	48.79	141.49
2013 benefits:			
Low gas prices	$ 20.68	($ 2.89)	$ 50.81
Base gas prices	55.50	40.05	137.07
High gas prices	102.45	91.68	240.63

SCE used natural gas price forecasts developed by Global Insight. Compared to the CEC forecasts used by the CAISO, the Global Insight forecasts contain slightly lower gas prices and a higher California-Arizona price difference. Because lower gas prices would tend to make DPV2 look less economic while a larger California-Arizona price difference would tend to make DPV2 look more economic, the extent to which gas price assumptions contribute to the differences in SCE and CAISO results is unclear.

SCE developed a probability distribution function based on historical gas price fluctuations to model uncertainty in future gas prices. DRA takes issue with the variations in gas prices that SCE modeled, because SCE included the California energy crisis period in the historical gas price data used to estimate future volatility. DRA submits that the events during that period, including market manipulation, suggest that the period's data are not representative of reasonable future market outcomes. DRA undertook a statistical analysis in which it excluded gas price data from the energy crisis period, and found almost 40% lower volatilities in Topock winter gas prices and about 50% higher correlations in winter prices among the gas pricing basins, compared to the relationships SCE assumed in its modeling. DRA did not quantify the impact on DPV2 economic results.

In its WES Reference Case, DRA used a November 2005 forecast of gas prices at Topock for 2009 and 2010. As can be seen from Table 7, DRA's gas price forecasts are higher than those used by the CAISO and SCE, and the Arizona-California price differential used by DRA is higher than that used by the CAISO and the same as the one used by SCE. Because of these differences, DRA's gas price forecasts would tend to make DPV2 look more economic than would the forecasts used by the CAISO and SCE.

SCE provided an October 2005 update to the Global Insight natural gas price forecast, which is included in Table 7. The natural gas prices in this update are higher than those used by the CAISO and SCE, but less than the prices used by DRA in their economic evaluations. The Arizona-California price differential in this forecast is $0.46 per mmBtu, higher than the differentials used in any of the economic evaluations. DRA provided a late-filed update to its assumed gas price for 2013, using January 16, 2006 Topock futures prices for 2009 and 2010. While no party updated its economic evaluation of DPV2 using these updated gas price forecasts, it is clear that these higher gas prices would increase the value of DPV2 substantially as long as the Southwest has surplus generation with attractive fuel efficiencies.

c) Mitigation of Market Power

All parties agree that the increased transfer capability added by DPV2 would reduce generators' ability to wield market power through strategic bids above system marginal costs, with resulting ratepayer benefits. Parties disagree regarding the extent to which forecasts of these market power mitigation benefits should be relied upon in determining the likely economic benefits of DPV2.

SCE and DRA did not model strategic bidding or estimate the ability of DPV2 to mitigate generators' market power. These parties express skepticism about the ability to quantify market power mitigation benefits with any degree of reliability. Global Energy states that it would be desirable to analyze the benefits of reducing market power if cost-based studies without strategic bid markups show insufficient project benefits, but submits that the CAISO's approach must be refined and undergo further testing before it can be accepted.

The CAISO simulated generators' exercise of market power via strategic bid markups, using an empirical approach in which it correlated historical market prices above marginal costs with two measures of market concentration. In Table 9, selected results illustrate DPV2 benefits that the CAISO forecasts due to mitigation of market power. To facilitate comparison, this table presents only CAISO scenarios that include base-case forecasts of load, gas prices, and hydro conditions, so that the differences reflect solely the CAISO's modeling of market power. A comparison of the No Market Pricing, i.e., marginal cost-based pricing, and Medium Market Pricing results indicates annual societal and CAISO ratepayer benefits ranging between $15 million and $56 million due to reduction in producers' market power.

Table 9

CAISO Evaluations of DPV2 Annual Energy Benefits
with Varying Levels of Market Pricing

(Base-case Load, Gas Price, and Hydro Conditions)
($Million Nominal)

	Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP + Contract Path)
2008 benefits:			
No market pricing	$ 42.89	$ 19.81	$ 70.83
Medium market pricing	58.85	37.87	98.74
High market pricing	71.12	54.82	124.50
2013 benefits:			
No market pricing	$ 55.54	$ 40.05	$ 137.07
Medium market pricing	77.43	54.88	193.50
High market pricing	93.86	65.22	237.23

As we would expect, the CAISO reports that the highest DPV2 benefits due to market power mitigation would occur if there high loads, high gas prices, and dry hydro conditions. The CAISO forecasts that DPV2 would provide large market power mitigation benefits under this combination of extreme conditions, with annual energy benefits generally ranging between $54 million and $321 million more with medium market pricing than if no market power is assumed.

We agree that a transmission project such as DPV2 can provide important benefits due to the resulting reductions in market concentration and generator market power. As we recognized in D.06-11-018, the CAISO has made substantial advances in its efforts to forecast strategic bidding and the ability of a transmission upgrade to reduce generators' market power. However, we questioned the manner in which the CAISO used historical data to predict future generator bidding behavior. Among our concerns, the anticipated CAISO LMP-based market, along with strengthened market power mitigation and monitoring, and resource adequacy and capacity requirements, will differ substantially from the historical circumstances that underlie the CAISO's bidding algorithms. We also questioned the reasonableness of the CAISO's use of statistically derived market-wide price-cost markups to approximate individual generators' bid-cost markups. Another concern we expressed in D.06-11-018 is that the CAISO did not verify the predictive ability of its market power model.

Our concerns regarding reliance on the CAISO's estimations of benefits due to DPV2's mitigation of market power are compounded by the difficulties in modeling congestion revenues between the CAISO control area and Arizona. As can be seen in Table 9, the CAISO forecasts much higher market power mitigation benefits in the CAISO Ratepayer (LMP + Contract Path) calculation than in the CAISO Ratepayer (LMP Only) calculation. The compounding effects of the uncertainties regarding the CAISO's estimates of both congestion revenues and market power mitigation increase our reluctance to rely on the estimates of market power mitigation benefits submitted by the CAISO for DPV2. Nevertheless, the CAISO results illustrate the value of DPV2 in reducing producers' ability to elevate prices due to market power.

d) Treatment of Generation Units Owned or Controlled by CAISO-Area Utilities

As modeling simplifications, SCE and the CAISO assume in their economic evaluations of DPV2 that all energy will be bought and sold at spot market prices, and that no new generation will be owned or controlled by CAISO utilities. DRA bases its economic evaluation of DPV2 on modifications to SCE's base case and, thus, also incorporates these assumptions. However, DRA is concerned that both of these simplifications tend to overestimate DPV2 benefits.

The assumption that all energy is bought and sold at spot market prices credits DPV2 with price reductions for all energy sold, to the extent that DPV2 reduces spot market prices. DRA points out that, in reality, much of the utilities' energy needs are met by cost-of-service generation and by power contracts whose costs to ratepayers may be either partially or entirely insensitive to spot market prices.

We agree with SCE that calculating DPV2 benefits as if existing utility-owned generation is sold at spot market prices does not bias the calculated CAISO Ratepayer energy benefits. While the assumption of spot market prices for all utility-owned generation is incorrect, in the calculation of CAISO Ratepayer benefits the resulting (and also erroneous) increase in the utilities' producer surplus is passed on to ratepayers. Thus, the erroneous increases in consumer and producer surpluses due to utility-owned generation offset each other, with no net effect on the calculated CAISO Ratepayer benefit.

DRA is correct that, to the extent that CAISO-area load is served by new utility-owned generation, or through existing or new spot price-hedging contracts with merchant generators or non-CAISO area utilities, the assumption that DPV2 will decrease spot market prices for such power would overestimate energy benefits to CAISO ratepayers. This is because, unlike existing utility-retained generation, the resulting erroneously assumed increase in producer surplus is not included in the calculation of CAISO Ratepayer benefits and thus does not offset the erroneous increase in consumer surplus. The CAISO's inclusion of market power mitigation benefits for DPV2 amplifies these overestimations of DPV2 benefits in the CAISO's evaluation.

We recognize the inherent difficulties and imprecision in forecasting the nature of future energy sources and the pricing terms by which energy will be sold to CAISO-area utilities. Without knowing the extent to which these modeling simplifications overestimate DPV2 benefits, we consider this uncertainty along with other factors in assessing the likely economic benefits of DPV2.

e) Extrapolation of Energy Benefits After the Study Period

In calculating the value of DPV2 energy benefits, SCE, the CAISO, and DRA extrapolated benefits for the last year simulated and then discounted the future benefits to produce either a present value (SCE and DRA) or a levelized annual value (the CAISO). SCE and DRA modeled WECC system operation and DPV2 energy benefits from June 1, 2009, the anticipated in-service date, through December 2015, and then calculated energy benefits beyond 2015 assuming that annual benefits remain constant in real inflation-adjusted dollars.

Although DPV2 is projected to commence operations in mid-2009, the CAISO conducted its analysis of DPV2 for 2008 and 2013 because the SSG-WI database used in the CAISO's assessment had been developed for the years 2008 and 2013. The CAISO assumes a 1% real (adjusted for inflation) escalation rate for energy benefits after 2013, for the remainder of the assumed economic life.

We are not convinced that DPV2 energy benefits are likely to escalate at 1% in real terms each year after 2013, as assumed by the CAISO. The CAISO justifies this assumption based on expected above-inflation escalation of commodity prices and an anticipated replacement of coal by gas as the marginal electricity source that determines market prices. However, DRA and SCE forecast that, with operation of DPV2, the surplus energy from the Southwest that will displace higher-cost California generation will already be almost exclusively gas-fired, not coal-fired, during the studied 2009 – 2015 period. Additionally, continuation of DPV2 energy benefits beyond the study period is based in significant part on expectations that current locational differences in gas prices and gas-fired generator efficiencies are likely to continue, and that there will continue to be generation surplus in the Southwest and particularly in Arizona. On balance, we find that SCE's and DRA's view that annual DPV2 energy benefits are likely to remain constant in real terms is the more realistic assumption.

As indicated in a sensitivity calculation performed by the CAISO, use of an assumption that annual DPV2 benefits will remain constant in real terms after 2013, rather than escalate faster than inflation, would decrease the levelized energy benefits and benefit-cost ratios that the CAISO calculated for DPV2 by about 9%.

f) Contingency Analyses

The CAISO and DRA evaluated the economic impacts of several potential market conditions whose likelihood of occurrence may be too low and uncertain to warrant inclusion in benefit-cost ratios. Although individually unlikely, these contingency events could have a significant effect on the cost-effectiveness of DPV2 if they do occur. Such contingency analyses are useful in that they shed light on the extent to which DPV2 may provide insurance value for high-impact, low-probability events. They also examine downside risks that unexpected market developments may render DPV2 uneconomic.

For DPV2, the CAISO analyzed eight contingency scenarios representing major transmission or generation outages or additions. In these contingency cases, the CAISO used base-case (medium) demand, gas price, hydro, and market (bid markup) conditions. The impacts of these contingencies on calculated 2013 energy benefits are summarized in Table 10.

Table 10

CAISO Evaluation of DPV2 Energy Benefits in 2013
Under Specified Contingency Conditions

(Base-case Load, Gas Price, and Hydro Conditions)
($2013 Million)

	Societal Perspective	Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP + Contract Path)
Base-case conditions	$ 58.83	$ 77.43	$ 54.88	$ 193.50
Add 1,200 MW of gas-fired combined cycle at Palo Verde	85.01	114.52	127.58	291.87
Add 2,400 MW of gas-fired combined cycle at Palo Verde	91.39	122.45	184.03	338.52
Mountainview plant out of service	58.85	92.95	77.95	267.30
Mohave coal plant in service	73.68	96.21	104.22	242.96
San Onofre nuclear plant out of service	85.82	134.10	145.74	380.68
Pacific DC intertie out of service	63.80	84.73	51.92	214.81
10% lower transfer capability for Paths 49	61.53	80.65	99.59	123.99

and 66				
Retirement of 3 units in SCE control area	56.51	74.11	43.75	191.39

Because the two versions of CAISO Ratepayer benefits reported by the CAISO only bracket expected benefits with some inaccuracy, the reported Societal and Modified Societal benefits are more instructive in our consideration of the CAISO's contingency scenarios. The Societal benefit provides an indication of WECC-wide energy savings with no market power mitigation attributed to DPV2, whereas the difference between the CAISO's Societal and Modified Societal results indicates market power reduction benefits that the CAISO attributes to DPV2.

The first two of CAISO's contingency scenarios consider the construction of new combined cycle plants in Arizona whose power could be transported over DPV2. It is expected that new gas-fired plants could be constructed with significant cost savings in Arizona. With assumed California-Arizona gas cost differences, these contingency scenarios indicate that access to this relatively inexpensive generation would provide significant energy benefits, with the first 1,200 MW plant increasing DPV2's Societal benefits by about 45%. It is informative, however, that DPV2 would provide only marginal additional energy benefits if 2,400 MW rather than 1,200 MW of new gas capacity is constructed in Arizona.

In three contingency scenarios, the CAISO considers generation reductions in SCE's service area, with the identified plants being out of service for the entire year. The additional benefits of DPV2 if the Mountainview plant is out of service appear to lie in its ability to thwart generators' exertion of additional market power, since the Societal benefits that exclude market power remain almost unchanged from the CAISO's base-case results. DPV2 would be more valuable during a complete outage of the San Onofre units.

In two scenarios, the CAISO considers transmission limitations. The value of DPV2 as insurance against an outage of the Pacific DC intertie or a reduction in the transfer capability of Path 49 (east of the Colorado River) and Path 66 (the California-Oregon intertie) appears limited.

DRA evaluates eight sensitivity and contingency cases, based on the Deterministic Reference Case that is a modification of SCE's base case. DRA reports the impacts of these contingencies on energy benefits for CAISO ratepayers for each year between 2009 and 2015. The average annual impacts of each of these contingencies are summarized in Table 11.

Table 11

DRA Evaluation of DPV2 Energy Benefits
Under Specified Contingency Conditions

(CAISO Ratepayer Perspective)
(2009 – 2015 Average, $2004 Million)

Deterministic Reference Case	$ 56.4
Palo Verde out of service	37.2
No Arizona-California gas price differential	48.7
Stirling solar installation	93.8
Postponement of California retirements	58.0
Alternative Arizona expansion	57.1
San Onofre out of service	90.8

DRA's Palo Verde outage scenario assumes that all three Palo Verde nuclear units are out of service for the entire study period. DRA reports that this would reduce DPV2 energy benefits to CAISO ratepayers by about one-third, compared to the otherwise identical Deterministic Reference Case, as power flows out of California to the overall benefit of Arizona ratepayers. DRA's "no gas price differential" scenario assumes that there is no gas price differential between Arizona and southern California. This would reduce CAISO ratepayer benefits by about 14%.

In the Stirling Solar scenario, DRA assumes that a 1,000 MW Stirling solar dish installation interconnects at the potential Midpoint substation near Blythe. DRA reports that this would increase DPV2 energy benefits by about 66%, largely because the solar installation would provide most of its output during daytime peak hours when the value of power will be high and surplus generation in Arizona is likely to be low.

DRA's California Retirement Postponement case assumes that 3,108 MW of California generation that is slated for retirement between 2006 and 2015 is not retired during the study period but instead remains in service. DRA finds that this would produce a very slight increase in DPV2 energy benefits.

In the Alternative Arizona Expansion case, DRA replaces 800 MW of generic coal plant addition that SCE assumes will be added in Arizona in 2013 and 2014 to maintain needed reserve margins. DRA replaces this capacity with 850 MW of gas-fired peaking and cycling capacity, to assess whether new peaking and intermediate capacity in Arizona would be more beneficial than addition of baseload generation. This produces a very slight increase in projected DPV2 benefits. Finally, like the CAISO, DRA evaluates a scenario in which both San Onofre units would be out of service for the study period. DRA's analysis indicates that DPV2 energy benefits to CAISO ratepayers would increase by 61% with the San Onofre outage.

The CAISO and DRA contingency analyses complement the evaluations of more likely market conditions, and enhance our ability to assess the value of DPV2. More exploration of conditions that could adversely affect DPV2's cost effectiveness would have been helpful. However, the studied contingency events confirm that the energy benefits of DPV2 may be enhanced considerably if the availability of surplus energy in the Southwest is increased or, to a lesser extent, if supply is removed from California.

4. DPV2 Non-energy Benefits

SCE and the CAISO attribute certain non-energy benefits to DPV2 that they include in the reported benefit-cost ratios. SCE reports (see Table 1 in Section III.A.2.a) that inclusion of DPV2 in transmission revenue requirements will increase SCE's transmission revenues from wheeling and Existing Transmission Contracts by $28.1 million on a net present value basis. SCE also reflects that the energy savings realized due to DPV2 will reduce ratepayer charges for franchise fees and uncollectibles, a forecasted net present value savings of $13.0 million.

The CAISO's economic evaluation includes significant non-energy benefits, which are shown in Table 4 in Section III.A.2.b. The largest non-energy benefit reported by the CAISO arises due to system operational savings. The CAISO projects that DPV2 will avoid the need to start and run at minimum load substantial amounts of high-cost generating capacity in southern California that would be needed otherwise to protect against outage contingencies for major transmission lines or nuclear units. The CAISO explains that the resulting

$20 million levelized annual benefit arises largely from avoidance of Minimum Load Compensation Payments to the uneconomic generators.

The CAISO also reports capacity benefits totaling $6 million per year for CAISO ratepayers and $12 million per year from the Societal perspective. These benefits reflect the CAISO's assessment of the value of the 1,200 MW of firm import capability added by DPV2. The CAISO assumes that capacity prices are capped at the cost of new peaking units. Based on its assessment that capital and fixed operating costs for a peaking unit are significantly less in Arizona than in California,[11] the CAISO assumes that the cost benefit of constructing peaking capacity in Arizona would be split equally between the buyers and sellers of capacity. The CAISO decreases the maximum savings benefit by an additional one-third to provide "a more conservative estimate" of the capacity cost savings attributable to DPV2, and obtains a total $12 million annual benefit.

The CAISO finds that operation of DPV2 will yield a net reduction in transmission losses, producing $1 million of levelized annual benefits to California ratepayers ($2 million on a Societal basis). The CAISO also reports a reduction in nitrogen oxide (NOx) emissions costs, based on lower emissions by new combined cycle plants in Arizona compared to emissions of older plants in California. The CAISO calculates $1 million of levelized benefits, based on the emissions reductions and the assumption that the value of NOx credits will be higher in California than in Arizona.

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[11] For simple cycle combustion turbines, the CAISO estimates that capital and fixed operating costs would be about 30% higher in California than in Arizona. This conclusion is based on assumptions that California has 43% higher labor costs, 67% higher land costs, and, accounting for most of the differential, air emission and water control technology costs that are more than triple the costs in Arizona.

We have concerns regarding the capacity value that the CAISO attributes to DPV2. While there currently is excess summer peak capacity in the Southwest, forecasted growth in that region is such that most, if not all, of the excess capacity would be needed to meet summertime needs in the Southwest by the time DPV2 is operational. In its updated evaluation of DPV2, SCE forecasts that no existing Arizona capacity would be available to provide firm capacity to California when DPV2 comes online. The WECC forecasts a regional reserve margin for the Southwest of 21% in 2008, declining to 19% in 2013. Thus, it appears likely that DPV2 would be able to deliver 1,200 MW of firm summer peak capacity to California only if additional capacity is built in Arizona for that purpose.

If additional capacity were to be built in Arizona to provide firm capacity to California, it is unclear whether peakers or combined cycle plants would be more economical. The DRA and SCE evaluations indicate that, while Arizona's existing capacity may be needed to meet local summer peaks by the time DPV2 comes online, Arizona is projected to maintain significant excess gas-fired capacity in winter that can be used to provide economical energy to California. The Southwest is expected to continue to have surplus low-cost generation in winter because winter peaks there are low compared to summer peaks. Because of this, both SCE's and DRA's analyses indicate that the bulk of DPV2's energy benefits would accrue in winter months, particularly in on-peak hours of winter months. Thus, a potential builder of new generation in Arizona would need to consider this competition for seasonal energy production in deciding whether to build new generation for export to California.

We recognize that difficulties in siting new generation in California, combined with cost differentials that may exist, may motivate generators to construct outside of California to meet California capacity needs. However, for the above reasons, we believe that it is speculative to assume that new power plants will be constructed in Arizona such that the full 1,200 MW transfer capability of DPV2 will be used to deliver firm summer peak capacity to southern California.

In summary, the CAISO's forecasts of the value of the non-energy benefits of DPV2 may be reasonable. However, we are not convinced that the full capacity benefit the CAISO attributes to DPV2 will be realized.

5. DPV2 Costs

a) Costs of Proposed Route and Authorized Route Alternatives

SCE provided cost estimates for its proposed route for the DPV2 project and for several alternative routes considered during the proceeding. No other party contested or presented evidence regarding SCE's cost estimates. As a result, we accept SCE's cost estimates for the DPV2 route alternatives authorized in this decision.

SCE's cost estimate for its proposed route for DPV2 is $577,663,000 in 2005 dollars, including pension and benefits, and administrative and general overheads. This cost estimate must be adjusted to reflect the authorized project route and route segments.

We find in Section IV that the West of Devers 230 kV upgrades included in SCE's proposed project are not feasible, and we authorize SCE to construct the Devers-Valley No. 2 500 kV line instead. Use of Devers-Valley No. 2 instead of the 230 kV upgrades reduces SCE's DPV2 cost estimate to $545,285,000. We authorize SCE to terminate the Devers-Harquahala 500 kV line at either the Harquahala power plant, as reflected in SCE's proposed project, or at a new Harquahala Junction that would shorten the route by five miles. SCE estimates that construction of Harquahala Junction would reduce costs by $24,080,000. In the vicinity of the Alligator Rock ACEC, we authorize SCE to construct DPV2 either adjacent to DPV1, as in SCE's proposed route, or using the Alligator Rock—North of Desert Center alternative. SCE estimates that the Alligator Rock—North of Desert Center route segment would add $8,952,000 to the cost of DPV2, including Allowance for Funds Used During Construction (AFUDC). While not provided by SCE, we estimate based on the amount of AFUDC in other SCE cost estimates that a comparable cost estimate for the Alligator Rock—North of Desert Center segment excluding AFUDC would be approximately $8,284,000.

b) Specification of Maximum Reasonable Cost

Pursuant to § 1005.5(a), we have jurisdiction and the responsibility to specify in the CPCN a "maximum cost determined to be reasonable and prudent" for the DPV2 project. While the Federal Energy Regulatory Commission (FERC) ultimately will decide how much of the costs for this project SCE may recoup in transmission rates, we believe our cost cap has bearing on the amount SCE may seek from FERC.

We adopt a maximum cost for DPV2 pursuant to § 1005.5(a) of $545,285,000 in 2005 dollars, including pension and benefits, and administrative and general overheads. This maximum authorized cost is decreased by $24,080,000 if the Devers-Harquahala line is terminated at Harquahala Junction. The maximum authorized cost is increased by $8,284,000 if the Alligator Rock—North of Desert Center route segment is used. These costs are in 2005 dollars. As SCE requests, in assessing compliance with these cost caps, SCE may deflate actual expenditures to their equivalent value in 2005 dollars using the Handy-Whitman Index of Public Utility Construction Costs.

SCE's cost estimates are based on preliminary design work. SCE requests that the Commission authorize it to seek additional cost recovery based on changes in cost estimates due to the adopted mitigation measures and mitigation monitoring program, final design criteria, and other factors.

We believe that SCE included sufficient allowance for contingency costs—almost 15%—to accommodate final design changes, as well as the adopted EMF mitigation, environmental mitigation, and mitigation monitoring program. The contingency budget may also be sufficient to accommodate possible routing changes in the Kofa and Alligator Rock areas, as discussed in Section IV.A. If, upon completion of the final, detailed engineering design-based construction estimates for the authorized project, SCE concludes that the costs will be materially (i.e., 1% or more) lower than the maximum cost we adopt, SCE should submit its updated cost estimate with an explanation of why we should not revise the maximum cost downward to reflect the new estimate. If SCE's final estimate exceeds the maximum cost we have adopted, SCE should seek an increase in the approved maximum cost pursuant to § 1005.5(b), at which time we will assess whether the cost increases affect the cost effectiveness and need for the DPV2 project.

c) Effect of Route Alternatives on Cost-effectiveness of DPV2

SCE, the CAISO, and DRA based their economic evaluations of DPV2 on the project route proposed by SCE in its application. At the ALJ's request, SCE submitted late-filed exhibits indicating how construction cost changes associated with route alternatives would affect the parties' economic evaluations of DPV2.[12] Because construction of the Devers-Valley No. 2 500 kV alternative would be less expensive than SCE's proposed 230 kV upgrades west of the Devers substation, this route alternative would increase the benefit-cost ratios for DPV2 by about 3.3%. Similarly, termination of DPV2 at Harquahala Junction in Arizona would be less expensive than the SCE-proposed termination at the Harquahala power plant, and would increase benefit-cost ratios by about 5.0%. SCE did not provide benefit-cost results for the Alligator Rock—North of Desert Center route alternative, but we estimate that this more-expensive alternative would reduce benefit-cost ratios by about 1.5%.

6. Discount Rates

Consistent with our determination in D.06-11-018, it would be appropriate to use SCE's most recently adopted weighted cost of capital as the discount rate in evaluating the benefits of DPV2. In D.05-12-043, the Commission adopted an 8.77% rate of return for SCE for 2006. In D.06-08-026, we granted SCE's request to waive a test year 2007 cost of capital application, so that the authorized 8.77% rate of return is also applicable during 2007.

SCE and DRA discounted future DPV2 benefits and costs to 2005 using a 10.5% nominal discount rate, stated to be SCE's most recently established incremental cost of capital. The CAISO discounted future DPV2 benefits and costs at a real discount rate of 7.16%, stated to equal SCE's weighted cost of capital. Assuming the long-term annual inflation rate of 2.28% used in SCE's assessment, this would equate to a nominal discount rate of 9.44%.

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[12] We address DPV2 project costs in Section III.A.5 and DPV2 route alternatives in Section IV of this decision.

Based on the yearly DPV2 energy benefit and cost results that SCE reported in Exhibit 6, use of an 8.77% discount rate rather than a 10.5% discount rate would increase the CAISO Ratepayer perspective benefit-cost ratio that SCE calculated from 1.71 to 1.88, an increase of about 10%. The record does not contain comparable yearly results for the DRA and CAISO evaluations of DPV2. However, with use of an 8.77% discount rate, we would expect a similar percentage difference in the benefit-cost ratios found by DRA. It appears that the impact of an 8.77% discount rate on the benefit-cost ratios found by the CAISO would be less than 5%, since the discount rate it used was closer to the currently authorized rate of return.

7. Load Forecasts and Baseline Resource Plans

As we noted in D.06-11-018, the applicant's resource plan and assumptions about transmission and generation resources in other portions of the study area are important components of the economic evaluation of a proposed transmission project.

In its economic evaluation of DPV2, SCE used the system database it maintains for the Commission's long term procurement proceeding, but updated its forecasts for loads, natural gas prices, and available hydro generation. SCE included increased energy efficiency, demand response, and renewable resources sufficient to meet the State's renewables goals. SCE determined that generation should be retired based on published retirement dates, if a plant reaches a life of 55 years, or if retirement is planned due to air quality restrictions. DRA used SCE's resource plan and load forecast assumptions in its own economic evaluation of DPV2.

The CAISO modeled the transmission and generation system using the SSG-WI database, which the CAISO modified in consultation with SCE to improve its representation of the SCE system. The CAISO describes that it added generation resources to the SSG-WI database to reflect renewables goals in each state, and added new gas-fired generation, primarily combined cycle plants, in each of the WECC areas as needed to maintain at least a 15% planning reserve margin. The CAISO also states that it added a few new thermal units that were economically attractive after renewable and capacity adequacy standards were met.

No party takes issue with the load forecasts and resource plans used in the economic evaluations of DPV2. DRA calls attention to one difference between the baseline resource plans developed by SCE and the CAISO: the CAISO included series capacitor upgrades sponsored by the Salt River Project, referred to as the East of River (EOR) 9,000+ project. SCE's (and therefore DRA's) assessment did not include these upgrades. The effect of this exclusion is that the SCE and DRA assessments reflect a lower baseline transfer capability, potentially translating into higher energy benefits attributed to the 1,200 MW increase in transfer capability due to DPV2. However, DRA did not make a recommendation regarding whether SCE should have included the EOR 9,000+ upgrade in its baseline resource plan. In their economic evaluations of DPV2, no party assumed that construction of DPV2 would affect the resource plans in other respects.

B. Nonquantified DPV2 Benefits

Some potential economic benefits of DPV2 are difficult to quantify. Each of the three economic evaluations of DPV2 discusses certain potential benefits in qualitative terms. Most of the potential benefits discussed qualitatively by one party were addressed quantitatively by another party in its evaluation of expected energy benefits (mitigation of market power), non-energy benefits (operational and capacity values, value of reduced emissions and transmission line losses), or contingency value (effects of new generation east of Devers, emergency generation or transmission outages, and gas price fluctuations).

In addition, parties credit DPV2 qualitatively with potential benefits to the extent it allows earlier retirements of aging power plants, encourages fuel diversity, allows reserve sharing, and/or increases voltage support for Southern California. The parties' discussion of these potential additional benefits of DPV2 is useful in extending our attention beyond the limits of the quantitative analysis. We consider these factors in our consideration of DPV2's economic value, even though their potential benefits have not been measured.

C. Alternatives to DPV2 and the No Project Alternative

Our evaluation of whether SCE should be granted a CPCN to construct the DPV2 project would not be complete without consideration of alternative resources that could be added or other actions that could be taken in lieu of the proposed project. Additionally, in accordance with CEQA requirements, the Final EIR/EIS evaluates the No Project alternative. In essence, the No Project alternative examines impacts if the proposed project, or a variation thereof, is not approved and built.

1. Alternatives to DPV2

In D.04-12-048, the Commission directed SCE and the other investor-owned utilities to follow the loading order in the Energy Action Plan (EAP). The updated EAP II[13] requires that the investor-owned utilities integrate all cost-effective energy efficiency into their resource plans. EAP II also requires inclusion of reasonable amounts of demand response and the procurement of renewable generation to the fullest extent possible. The Renewable Portfolio Standard (RPS) program as originally established required 20% of electricity sales to come from renewable sources by 2017, but that 20% goal has been accelerated from 2017 to 2010.

In D.04-12-048, the Commission found SCE's long term procurement plan to be reasonable, subject to revision to include energy efficiency targets as adopted in D.04-09-060 and demand response programs proposed for implementation in Rulemaking 02-06-011. In its economic evaluation of DPV2, SCE includes the resources that are in its long term procurement plan, with increased energy efficiency, demand response, and renewable resources sufficient to meet the State's RPS goals. We agree with SCE and the CAISO that additional development of energy efficiency, demand response, and renewable generation beyond the targets already set is not a feasible or cost-effective alternative to DPV2, as discussed more fully below.

In this proceeding, DRA and the CAISO assess possible development of combined cycle generation in southern California as an alternative to DPV2. The Final EIR/EIS suggests that new combined cycle plants could be built near the Devers, Etiwanda, and/or Valley substations.

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[13] EAP II, a policy statement issued jointly by the Commission and the CEC, established a set of priorities for the energy policy for the State. See http://www.cpuc.ca.gov/PUBLISHED/REPORT/50480.htm.

DRA compares the addition of five 250 MW gas-fired combined cycle generators in California to construction and use of DPV2 to tap surplus generation from existing gas power plants in Arizona. DRA reports that ratepayers could finance construction of the California plants under 10-year power purchase agreements for approximately the same present value cost as the cost of building DPV2. DRA calculates that, with the new California gas generation, CAISO ratepayer benefits would be only 61% of the ratepayer benefits produced by accessing surplus Arizona energy via DPV2. DRA concludes that the alternative of investing additional capital in new California generation appears to be less preferable than building DPV2.

The CAISO compares the cost of building a new combined cycle plant in California with the cost of building a comparable new plant in Arizona to provide power to California using DPV2. The CAISO estimates that construction and operating costs for a combined cycle plant built in Arizona would be about 10% less than costs for a California plant. It finds that baseload power from such a plant in Arizona, delivered to California via DPV2, would be about 4% more expensive than power from a new gas plant in California, due to allocation of a share of DPV2 costs. The CAISO cautions, however, that its California combined cycle cost estimate does not include transmission or gas interconnection costs, which it could be substantial.

The CAISO submits that California needs to add 5,000 MW or more in the next five years due to load growth and generation retirement. In its opinion, both additional generation in southern California and inter-regional transmission upgrades including DPV2 should be pursued. SCE concurs with the CAISO that both generation and transmission options are needed, and submits that non-transmission alternatives could not meet all of the project objectives and/or could not be counted on to develop fast enough or in enough magnitude to avoid need for the DPV2 project.

We agree with SCE and the CAISO that there is need to pursue a range of resources, including inter-regional transmission, in-state generation, and other alternatives. In D.06-07-029, the Commission found that, in order to maintain adequate capacity and reserves throughout the state, 3,700 MW of new generation must come on line beginning in 2009. The required new resources are in addition to the expected investment in energy efficiency and renewable generation, and are in addition to planned transmission upgrades. As the CAISO points out, new or refurbished generating units are likely to be needed in southern California for reliability and operational purposes, but siting opportunities may be limited. At the same time, an expanded transmission system would increase access to competitively priced energy, provide more flexibility in operating the grid, and increase grid reliability. We conclude that, even with the emphasis on energy efficiency, demand response, renewable resources, and distributed generation, investments in both transmission and conventional power plants will be needed.

As SCE and the CAISO describe, several potential transmission projects that could increase transmission transfer capability between California and the Southwest were evaluated. The STEP process screened alternative transmission upgrades and undertook technical and economic studies to develop a consensus expansion plan, which includes both DPV2 and upgrades to series capacitors for DPV1 and the Southwest Power Link. Based on SCE's and the CAISO's showings, we find that the range of potential transmission alternatives has been considered carefully and that DPV2 is the preferred new transmission alternative to provide access to lower-cost energy in the Southwest.

2. The No Project Alternative

Under the No Project alternative considered in the Final EIR/EIS, DPV2's 1,200 MW of transfer capability would not be added, and the existing transmission grid and power generating facilities would continue to operate. To serve the expected continued growth in electricity consumption and peak demand within California, additional electricity would need to be generated within California or imported into California by existing transmission facilities. In the No Project alternative, there could be supply-side actions, including accelerated development of conventional, renewable, and distributed generation, or other major transmission projects. Additional energy conservation or load management could also be pursued.

The Final EIR/EIS states that the continued operation of existing gas-fired turbine generators and construction of new generation and transmission lines would have long-term environmental impacts including substantial air emissions and ongoing noise near the generators, and visual impacts depending on the locations of new transmission lines and generators. The Final EIR/EIS does not find that the No Project alternative would be environmentally preferable to the Environmentally Superior configuration of the DPV2 project.

As we discuss above, because of both the magnitude of resource additions that are needed and the operational, system reliability, and other benefits that transmission upgrades such as DPV2 would provide, the No Project scenario is not a desirable alternative to the DPV2 project.

D. Discussion

The Commission must take into account a wide range of factors consistent with §§ 1001, 1002, 1005.5, GO 131-D, and other statutory and regulatory requirements in evaluating whether to authorize DPV2. As we explain in this section, there is adequate record support that SCE should be granted a CPCN for the DPV2 project.

As we describe above, SCE, the CAISO, and DRA performed separate economic evaluations of the DPV2 project, using different methodologies, assumptions, and scenarios. All three parties reach similar conclusions that DPV2 would be cost-effective for CAISO ratepayers, with DPV2 likely to provide significant economic benefits in excess of its costs over a wide range of market conditions. SCE reports a likely benefit-cost ratio of 1.71 from the CAISO Ratepayer perspective (Table 1). The CAISO finds that the benefit-cost ratio from the CAISO Ratepayer perspective will be between 1.25 and 3.34, and that the benefit-cost ratio from a Societal perspective is either 1.35 or 1.77, depending on whether forecasted market power mitigation benefits are included (Table 4). DRA's evaluation in its WES Reference Case finds a CAISO Ratepayer benefit-cost ratio of 1.31 (Table 5).

In addition to quantified economic benefits, the parties cite several other benefits as further support for their recommendations that the Commission authorize SCE to construct DPV2. In assessing need for the project, we must weigh the significant economic and other benefits that are expected to accrue against the undesirable environmental effects that DPV2 may cause.

In concluding that DPV2 should be authorized, the parties focus on the economic benefits that would accrue because of the 1,200 MW increase in the transfer capability between California and Arizona. Access to Southwest generation is limited currently by congestion over the transmission interfaces between southern California and the Southwest. The increased access that DPV2 would provide to less expensive generation in Arizona and elsewhere in the

Southwest would allow higher-cost generation in California to be replaced and would reduce the cost of energy to CAISO ratepayers.

In Section III.A.3.a, we describe differences among the parties' production cost modeling of the energy benefits of DPV2. As we found in D.06-11-018, both the network model used by the CAISO and the transportation model used by SCE and DRA in this proceeding have strengths and weaknesses. While a network model such as used by the CAISO has the potential for greater accuracy in LMP-based markets, such a model has difficulties in modeling dispatch and congestion costs on inter-regional transmission projects like DPV2. This limitation reduces the precision of the CAISO's estimates of DPV2 energy benefits. As reflected in Table 4 above, the CAISO was only able to bracket expected CAISO ratepayer benefits with a wide range of uncertainty. At the same time, concerns have been raised regarding SCE's validation of the more simplified transportation modeling used in SCE's and DRA's evaluations of DPV2. In light of these concerns, we conclude that there is value in the use of both network and transportation models in evaluating DPV2. As TURN suggests, we have greater confidence in the results of the parties' evaluations since SCE, the CAISO, and DRA modeling efforts produce comparable and consistent results.

In Section III.A, we have identified several aspects of the economic evaluations that, individually, may tend to bias DPV2 benefit estimates either positively or negatively. There are several ways in which parties may have underestimated the likely value of DPV2.

First, natural gas prices have increased, particularly from the levels used in the SCE and CAISO economic evaluations. DRA found that DPV2 would be cost-effective if Arizona gas prices reach $5.00 per mmBtu in 2010 with a

California-Arizona gas price differential in excess of $0.50 per mmBtu, or if gas prices reach at least $6.40 even with no California-Arizona price differential.

Second, SCE and DRA did not reflect that some producers may be able to markup bids above marginal costs in an exercise of market power. We agree that, by increasing the amount and diversity of suppliers with access to the California market, DPV2 will enhance competition and reduce the potential for generators to exert market power. While we are not convinced that the CAISO's market power estimations are reliable, it is clear that DPV2 would provide some amount of market power mitigation, with benefits to CAISO ratepayers.

In its WES Reference Case, DRA evaluated DPV2 benefits using only base-case market conditions. Due to asymmetry in how energy costs are influenced by variations in system conditions, consideration of the effects of volatility in factors such as loads, gas prices, and hydro conditions likely would yield a higher expected value of DPV2 energy benefits, compared to an evaluation of benefits looking only at expected market conditions. As an example, high gas prices have a greater effect on DPV2 benefits than would low gas prices, as illustrated in Table 8.

Additionally, the CAISO and DRA benefit calculations do not recognize that wheeling customers and entities with Existing Transmission Contracts would contribute to DPV2 cost recovery, or that revenue requirements for franchise fees and uncollectibles would decline due to energy cost reductions attributed to DPV2. Similarly, SCE and DRA evaluations do not include economic benefits arising due to operational benefits, emissions savings, or reduced transmission losses, as found by the CAISO.

Another source of potential underestimation of DPV2 benefits is that the discount rates that SCE, the CAISO, and DRA used are all higher than SCE's cost of capital. Consistent with D.06-11-018, use of a discount rate equal to 8.77%, the cost of capital authorized most recently for SCE in D.05-12-043, would increase benefit-cost ratios as reported by SCE and DRA by about 10%. An 8.77% discount rate likely would increase DPV2 benefit-cost ratios reported by the CAISO somewhat less than 5%.

Other choices in the parties' economic evaluations may tend to overestimate the value of DPV2. As discussed in Section III.A.3.d, the SCE, CAISO, and DRA evaluations assume that all energy is bought and sold at spot market prices, and that no new generation will be owned or controlled by CAISO utilities. These simplifying assumptions overestimate the value of DPV2 in decreasing spot market prices, to the extent that CAISO-area load will be served by new utility-owned generation, or by new or existing spot price-hedging contracts with merchant generators or non-CAISO area utilities.

As another concern, we are not convinced by the CAISO's assumption that annual DPV2 benefits will increase by 1% in real terms (adjusted for inflation) each year after 2013. As we describe in Section III.A.6, the more realistic assumption that annual DPV2 energy benefits will remain constant in real terms after 2013 would decrease the CAISO's benefit-cost ratios for DPV2 by about 9%.

Nor are we persuaded that the capacity benefits that the CAISO attributes to DPV will be realized, for reasons we discuss in Section III.A.6. With the expectation that generation capacity that meets the Southwest's summertime peak needs will continue to allow significant amounts of economical surplus energy to be available to California during non-peak periods, it is not clear that DPV2 will provide sufficient incentives to cause additional generation to be built east of Devers to provide firm capacity to California.

Finally, we note that the cost of DPV2 may change depending on routing choices and other factors, which would have a direct impact on the project's cost-effectiveness. As described in Section III.A.5, construction of the authorized Devers-Valley No. 2 route alternative is expected to increase benefit-cost ratios for DPV2 by about 3.3%. Termination of the DPV2 project at Harquahala Junction could increase benefit-cost ratios by about 5.0%, whereas use of the Alligator Rock—North of Desert Center route alternative could reduce benefit-cost ratios by about 1.5%.

Based on the parties' economic evaluations of DPV2 submitted in this proceeding, we conclude that DPV2 would provide significant economic benefits for CAISO ratepayers. It is our judgment that the described concerns about individual aspects of the parties' economic evaluations, taken together, strengthen rather than weaken this conclusion.

The benefit-cost ratios reported by SCE, CAISO, and DRA do not include certain potential benefits of DPV2 that do not lend themselves to economic quantification. DPV2 would expand the interstate regional transmission network and increase its reliability. With DPV2, the CAISO would have more flexibility in operating California's transmission grid and more options to respond to transmission and generation outages. Additionally, as indicated by several contingency scenarios reported in this proceeding, DPV2 would provide insurance value as an economic hedge against low-probability, high-impact events that could affect the availability and price of energy to southern California, including unexpected transmission and generation outages or increases in natural gas prices.

DRA voices a concern that the parties' economic evaluations do not reflect the possibility that there may be an unanticipated long-term trend away from recent system conditions, which DRA calls a paradigm shift. We agree that there is a risk that DPV2 would prove uneconomic due to unanticipated shifts in market conditions. However, DPV2 would also provide insurance value against other unexpected events that could greatly increase costs to CAISO ratepayers.

The record contains limited information regarding potential economic impacts of DPV2 in Arizona and other areas outside of California. SCE's 2004 economic evaluation shows negative energy benefits for Arizona (Table 3), such that Arizona electricity costs could increase slightly with DPV2's operation. However, SCE's evaluation assumes that no additional generation is built in Arizona to take advantage of the 1,200 MW of transfer capability added by DPV2. Nor does SCE's evaluation recognize that, with DPV2, the increased ability to pool resources could provide benefits to Arizona as well as to California. The increased transfer capability could be used to provide emergency support to Arizona as well as to California during unanticipated conditions such as the loss of a major generating facility or of another high-voltage transmission line, or during natural disasters. DRA's contingency scenario assessing a Palo Verde outage indicates the benefits of DPV2 to Arizona in that event.

In Section III.C, we determine that energy efficiency, demand response, and renewable generation do not hold sufficient near-term promise to provide a feasible or cost-effective alternative to DPV2. Nor would they offer the operational and other system benefits expected due to DPV2. New transmission and generation options, in addition to demand side resources, should be pursued to meet the need for new energy supply in southern California. We agree with SCE and the CAISO that DPV2 is the preferred new transmission project to increase transfer capability between southern California and Arizona.

As we describe in Section IV below, even with the mitigation measures made a condition of the CPCN, the DPV2 project would have significant unmitigable effects on visual resources, wilderness and recreation resources, cultural and paleontological resources, agriculture, noise levels, and air quality. Weighing the economic and other benefits that we expect DPV2 to provide and the identified environmental effects, we conclude that the substantial benefits expected due to DPV2 outweigh the environmental impacts of the project. We conclude that the DPV2 project is needed and in the public interest, and that we should grant SCE a CPCN to construct the DPV2 project, subject to the routing modifications and mitigation measures adopted in this decision.

IV. DPV2 Route Alternatives

In its application and PEA, SCE identified several alternative routes for portions of the DPV2 project. During the EIR/EIS scoping process, the Commission and BLM environmental team identified additional alternatives, including minor routing adjustments, entirely different transmission line routes, alternative energy technologies, and non-wires alternatives. Alternatives were then screened according to CEQA and NEPA guidelines to determine the alternatives to carry forward for analysis in the EIR/EIS. The environmental team rejected 26 alternatives that did not meet CEQA and NEPA criteria for analysis. The Final EIR/EIS provides a detailed analysis of seven alternatives to portions of the Devers-Harquahala segment of the proposed project, and one alternative to the upgrades proposed west of the Devers substation.

Based on comparison of the environmental impacts of the proposed project and alternatives, the Final EIR/EIS identifies the environmentally superior alternatives and the BLM Agency Preferred alternatives as follows:

- The eastern portion of the DPV2 project would begin at the new Harquahala Junction switchyard;

- The proposed project route from the Harquahala Junction switchyard to east of Alligator Rock;

- The Alligator Rock-North of Desert Center alternative to west of Alligator Rock;

- The proposed project route from west of Alligator Rock to Devers substation;

- The Midpoint substation proposed by SCE and the Midpoint substation identified as part of the Desert Southwest project are equally environmentally superior/preferable; and

- The proposed West of Devers upgrades unless determined to be infeasible, in which case the Devers-Valley No. 2 alternative would be constructed.

The Final EIR/EIS evaluated the environmental impacts of the proposed project and alternatives, classifying the impacts as Class I (significant and unavoidable or unmitigable), Class II (significant but mitigable to less than significant), Class III (adverse but less than significant), and Class IV (beneficial). The Final EIR/EIS found that the DPV2 project would have significant unmitigable impacts on visual resources, wilderness and recreation resources, cultural and paleontological resources, agriculture, noise levels, and air quality. In describing potential environmental impacts of the DPV2 project, we focus on the significant unmitigable (Class I) impacts, since we expect that the adopted mitigation measures will eliminate other potentially adverse environmental impacts of DPV2 or allow them to be reduced to less-than-significant levels.

In the following subsections, we address route segments and related alternatives, including the Desert Southwest transmission project as a potential alternative to the portion of the Devers-Harquahala line between a new Midpoint substation and the Devers substation. We then describe broader environmental impacts that arise due to multiple route segments or the DPV2 project as a whole.

A. Devers-Harquahala 500 kV Line

1. Description of Proposed Route

As proposed in SCE's application, the 230-mile Devers-Harquahala 500 kV transmission line would be constructed between the switchyard at the Harquahala generating station near the Palo Verde nuclear generating plant in Arizona and SCE's Devers substation in North Palm Springs, California. For most of the route, this new line would parallel SCE's existing 500 kV DPV1 transmission line. Approximately 102 miles of the line would be located in Arizona and the remainder in California. The Arizona portion of the Devers-Harquahala line would be located in a relatively undeveloped area of the western Sonoran Desert. A large portion of the proposed route in California is located within the Colorado Desert, which is the western extension of the Sonoran Desert. The region consists of mostly native desert habitats.

The Harquahala generating station is approximately 17 miles northwest of the Palo Verde generating station and approximately 49 miles west of Phoenix, Arizona. Departing from the Harquahala switchyard, the proposed DPV2 line would proceed easterly for approximately five miles to SCE's existing DPV1 route. The route would then turn north to parallel DPV1 through the southern end of the Big Horn Mountains, across the Harquahala Plain through the northern end of the Eagletail Mountains, through the Ranegras Plain, and across the northern portion of Kofa. The route would then traverse the La Posa

Plain and the northeastern corner of the Yuma Proving Grounds, then proceed through the central portion of the Dome Rock Mountains and cross the Colorado River and the Arizona-California state line.

There is one location where the DPV2 circuit would be placed on existing DPV1 towers rather than on new towers parallel to the DPV1 line. In Copper Bottom Pass in the Dome Rock Mountains, SCE proposes to place the DPV2 circuit on 13 existing 500 kV double circuit structures built as part of DPV1. SCE explains that double circuit construction was used in the narrow Copper Bottom Pass since there is not room for two single circuit lines. The double circuit towers are already strung with two circuits, with one circuit used for DPV1 and the second currently unused circuit proposed to be used for DPV2.

In California, the DPV2 route would continue to parallel DPV1, generally along I-10, between the town of Blythe at the California-Arizona border to the Devers substation, all in Riverside County. The route would proceed westerly from Blythe into the Palo Verde Valley. SCE describes a new Midpoint substation approximately 10 miles southwest of Blythe as an optional component that may be constructed jointly with the Desert Southwest transmission project proposed by Imperial Irrigation District (IID). The route would cross the Chuckwalla Valley Dune Thicket ACEC and, near Desert Center, the Alligator Rock ACEC. It would skirt the southern edge of Joshua Tree National Park and continue to parallel DPV1 to the Devers substation.

SCE proposes to construct a new optical repeater facility three miles west of Blythe, California within the DPV2 right of way. SCE also proposes to construct two series capacitor banks adjacent to existing DPV1 series capacitor banks, one in Arizona approximately 55 miles west of the Harquahala switchyard and one in California approximately 64 miles east of Devers. SCE proposes to install Special Protection Scheme relays at the Devers substation in California and the Palo Verde, Hassayampa, and Harquahala substations in Arizona. Other modifications would also be needed within the Harquahala and Devers substations. SCE also proposes to construct telecommunications systems related to the proposed project, including a new telecommunications facility on Harquahala Mountain adjacent to an existing facility of similar design.

2. Route Alternatives Near Palo Verde Generating Station

As proposed in SCE's application, the Devers-Harquahala line would begin at the switchyard of the Harquahala generating station, and would depart the Harquahala switchyard to the east paralleling the existing Harquahala-Hassayampa 500 kV line. Three route alternatives analyzed in the Final EIR/EIS involve different ways to terminate the DPV2 project in this area.

The Harquahala Junction alternative would entail construction of a new switching station east of the Harquahala generating station, at the point where the existing Harquahala-Hassayampa and DPV1 transmission lines diverge (a location called "Harquahala Junction"), which would become the eastern termination point of the DPV2 project. This alternative would avoid the need to construct the five-mile segment of the proposed project from the Harquahala switchyard to the new Harquahala Junction. SCE estimates that the Harquahala Junction alternative would cost $14.6 million less than termination of DPV2 at the Harquahala switchyard, due primarily to avoidance of five miles of transmission line construction.

The Harquahala-West alternative would begin at the Harquahala generating station switchyard. Rather than departing the Harquahala switchyard to the east, this alternative would depart the switchyard to the west and traverse west for approximately 12 miles to the El Paso natural gas pipeline corridor. The transmission line would proceed northwesterly along the pipeline corridor for approximately nine miles to the intersection with the DPV1 transmission line. This route would be 14 miles shorter than the proposed route.

In the Palo Verde alternative, the DPV2 line would terminate at the Palo Verde nuclear generating station switchyard instead of the Harquahala generating station switchyard. This alternative would avoid the need to construct the 5-mile segment between the Harquahala generating station switchyard and the Harquahala Junction, but would add construction of 14.7 miles of new transmission line parallel to DPV1 from Harquahala Junction to the Palo Verde switchyard.

The Final EIR/EIS concludes that the Harquahala Junction Switchyard alternative is environmentally preferred because it would require the least distance of transmission line construction outside of existing corridors and it would eliminate effects to agricultural lands.

SCE has an option agreement with the Harquahala Generating Company that would allow it to acquire the Harquahala switchyard and the existing Harquahala-Hassayampa 500 kV transmission line. SCE reports that it has been discussing an arrangement with Arizona Public Service and the Harquahala Generating Company whereby the three companies would share the Harquahala-Hassayampa 500 kV transmission line. This joint arrangement would allow Arizona Public Service to connect its planned TS-5 transmission line at the Harquahala Junction.

SCE should terminate DPV2 at a new Harquahala Junction or the Harquahala switchyard, subject to approval by the Arizona Corporation Commission and any other needed authorizations. Because this alternative is less costly than the proposed project and is also the environmentally preferred alternative, SCE should pursue good-faith efforts to reach a commercially reasonable agreement and seek the additional authorizations needed for construction of Harquahala Junction. If Harquahala Junction does not receive the needed approvals in Arizona or is otherwise not feasible, SCE may terminate DPV2 at the Harquahala switchyard.

3. Kofa National Wildlife Refuge

The proposed DPV2 route would traverse Kofa for approximately 24 miles, paralleling the DPV1 line approximately 2 miles south of Kofa's northern boundary. The Final EIR/EIS finds that, within Kofa, the proposed project would result in significant unmitigable (Class I) visual impacts and significant impacts on Kofa's recreational value.

In the EIR/EIS process, a preliminary environmental review was undertaken for three alternative route segments that potentially could reduce impacts in Kofa. As a result of greater impacts to recreation and to visual and biological resources, all three alternatives that would avoid Kofa were eliminated from full consideration in the EIR/EIS process. The Final EIR/EIS found that the route through Kofa is the most environmentally preferred.

We take official notice that the USFWS has issued a preliminary Determination of Incompatibility regarding the construction of DPV2 through Kofa as proposed by SCE. If the USFWS rejects the proposed route for DPV2 paralleling DPV1 through Kofa, that route will become legally infeasible. We authorize SCE to construct a route in the Kofa area that is acceptable to the USFWS and other permitting agencies, subject to a showing that the routing modification is not detrimental to the cost effectiveness of DPV2. Consistent with § 1005.5(b), SCE may seek an increase in the maximum cost for the DPV2 project that we find reasonable in Section III.A.5 of this decision, if an alternative route in the Kofa area is expected to cause DPV2 costs to exceed the adopted maximum cost.

4. Alligator Rock Area

BLM has designated the Alligator Rock ACEC for protection of its archeological features. The Final EIR/EIS identifies three potential reroutes in the Alligator Rock area that may reduce impacts to cultural and biological resources in the Alligator Rock ACEC.

a) Proposed Project Route

The proposed route for DPV2 would traverse the Alligator Rock ACEC for approximately 6.8 miles, paralleling the existing DPV1 transmission line. The Final EIR/EIS finds that this proposed route segment would have significant unmitigable impacts on visual and recreational resources in the Alligator Rock ACEC, in addition to more general significant impacts on air quality and cultural resources, which are discussed in Section IV.C. While the new transmission structures would be similar to those of the adjacent DPV1, the new structures would cause additional skylining[14] and view blockage of the Chuckwalla Mountains in the background. The new line would also increase the structural complexity and industrial character visible from several access roads within the Alligator Rock ACEC. With the amount of industrial development intensified, DPV2 would further degrade the landscape and character of the

[14] Skylining occurs when a transmission tower is seen with only the sky behind it, making it highly visible.

Alligator Rock ACEC, leading to a significant diminishment of its recreational value.

b) Alligator Rock—North of Desert Center Alternative

The Alligator Rock—North of Desert Center alternative route segment would avoid traversing the Alligator Rock ACEC. This 11.8-mile alternative would diverge from the proposed DPV2 route approximately five miles east of Desert Center. It would head northwest, cross I-10, and proceed north of Desert Center. The segment would then turn southwest and would parallel I-10 for 3.6 miles before crossing I-10 again and rejoining the proposed route. It would be primarily on BLM land, and on private land for three miles near its western end.

While this alternative route segment would have significant impacts on air quality and cultural resources (as would the proposed project and all alternatives), it would eliminate the proposed route's significant impact to wilderness and recreation, and it would reduce potential effects on highly valuable cultural resources because it would avoid the Alligator Rock ACEC. This alternative would create a different significant visual impact resulting from introduction of a new 500 kV transmission line into a rural landscape lacking similar structures of industrial character, with view blockage of sky and portions of the Chuckwalla Mountains and Alligator Rock in some locations.

c) Alligator Rock—Blythe Energy Transmission Route Alternative

This 4.6-mile alternative route segment would diverge from the proposed project route approximately 3.5 miles east of Desert Center. While within the Alligator Rock ACEC, this alternative would follow its northern edge near I-10. This alternative would follow the Blythe Energy transmission line route proposed by Blythe Energy LLC and would be close to an existing El Paso natural gas pipeline access road.

As with the proposed project and all alternatives, this alternative would have significant impacts on air quality and cultural resources, although the impacts on cultural resources potentially would have less value than those in the heart of the ACEC. The alternative would create different significant visual impacts and would alter the natural landscape of an undeveloped portion of the ACEC to an industrial use, changing the character of the Alligator Rock ACEC and significantly diminishing its recreational value.

d) Alligator Rock—South of I-10 Frontage Alternative

This 9.77-mile alternative route segment would follow the route proposed for the Desert Southwest transmission project (see Section IV.A.6 below). It would diverge from the proposed DPV2 route approximately 3.5 miles east of Desert Center and would follow the Alligator Rock—Blythe Energy route alternative to the point where that alternative turns southwest, just east of Alligator Rock. After passing between the northern end of Alligator Rock and I-10, this alternative route would continue in a westerly direction immediately south of I-10 before rejoining the proposed DPV2 route. For approximately two miles, it would be constructed within a new right of way inside the northeastern boundary of the ACEC.

This alternative would have significant impacts on air quality and cultural resources, as would the proposed project and other alternatives, although the affected cultural resources potentially could have less value than those in the center of the ACEC. This alternative would create different significant visual impacts and, while affecting a smaller area within the ACEC, would significantly diminish its recreational value.

e) Discussion

The Final EIR/EIS concludes that the Alligator Rock—North of Desert Center route segment is environmentally preferred because it would minimize biological, cultural, and wilderness area impacts, even though it would be closer to populated areas and would require two crossings of I-10.

SCE favors placing DPV2 adjacent to DPV1 through the Alligator Rock ACEC. SCE states that it has good information on the site features associated with Alligator Rock and believes that all significant features can be avoided with careful construction monitoring. SCE states that no comparable information exists for the North of Desert Center alternative, and that SCE has not surveyed the North of Desert Center route and has not acquired right of way for the route. SCE notes that, in any event, BLM must grant a permit for the DPV2 route in the Alligator Rock area, since all alternatives lie wholly or partially on BLM lands.

Because the Alligator Rock—North of Desert Center alternative, which crosses both BLM and private land, is the environmentally preferred alternative, SCE should construct the North of Desert Center alternative if BLM authorizes this route in its Record of Decision. It is reasonable to grant SCE the flexibility, if BLM does not authorize the Alligator Rock—North of Desert Center route segment, to build DPV2 on a route segment through the Alligator Rock ACEC that is authorized by BLM, if the segment received full consideration in the Final EIR/EIS, or if it deviates from one of the reviewed route segments solely within BLM land and BLM undertakes the environmental review needed under NEPA.

5. Desert Southwest Transmission Project and Midpoint Substation

The Desert Southwest transmission project proposed by IID would include a 118-mile 500 kV transmission line generally paralleling DPV1 and DPV2 between Blythe and SCE's Devers substation.

a) Desert Southwest Project as Proposed by IID

The Desert Southwest project would originate at a new Keim substation near the Blythe Energy Project power plant. Either a double-circuit 500 kV line or two parallel 500 kV lines would be constructed from the Keim substation to a new Midpoint substation to be located where the line(s) intersect the existing DPV1 line. The Desert Southwest route from the Midpoint substation to Devers generally would be parallel to and immediately north of SCE's right of way for DPV1 and DPV2. It would diverge from the DPV1 corridor only in the vicinity of the Alligator Rock ACEC, as described above in the Alligator Rock—South of I-10 alternative.

IID and BLM prepared a joint EIR/EIS regarding the Desert Southwest project. On September 15, 2006, BLM issued a Record of Decision allowing IID a right of way to use public lands to construct the Desert Southwest project, with the portion between the Blythe area and the Devers substation as a separate stand-alone transmission line adjacent to the DPV2 right of way. In its Record of Decision regarding the Desert Southwest project, BLM approved the Desert Southwest route that IID proposed in the vicinity of Alligator Rock, described in Section IV.A.4.d above. The Desert Southwest EIR/EIS did not consider an alternative north of I-10 in the vicinity of Alligator Rock comparable to the North of Desert Center alternative that the Final EIR/EIS for DPV2 found environmentally superior.

The Final EIR/EIS evaluates the Desert Southwest transmission project as a potential alternative to the portion of DPV2 between a new Midpoint substation and Devers. In this scenario, the Midpoint-to-Devers portion of the Desert Southwest project would carry up to 1,200 MW of load from the Blythe Energy Project and Arizona. The Final EIR/EIS also considers separately the cumulative environmental impacts if both DPV2 and the Desert Southwest project are built as separate 500 kV transmission lines.

Overall, the environmental impacts of the Desert Southwest project as an alternative to DPV2 would be very similar to those of the comparable portion of the proposed DPV2 project with the Alligator Rock—South of I-10 alternative. The Final EIR/EIS concludes that the proposed DPV2 project is environmentally preferred over the Desert Southwest project because it would require less ground disturbance and construction of fewer substations.

b) Possible Integration of DPV2 and Desert Southwest Transmission Projects

SCE and IID are in discussions to integrate the DPV2 and Desert Southwest transmission projects, so that only one 500 kV line would be constructed between a new Midpoint substation and Devers. SCE states that, if SCE and IID reach agreement, the cost to SCE would not exceed the cost of a stand-alone project and DPV2's cost-effectiveness would not be affected adversely. The transfer capability of DPV2 would be expanded from 1,200 MW to 2,340 MW, probably through upgrading series capacitors on the line. SCE would still turn over 1,200 MW of transfer capability to the CAISO, as SCE has proposed in A.05-04-015, and the remainder of the transfer capability would be managed by IID.

SCE describes that, if a joint DPV2-Desert Southwest project arrangement is reached with IID, the joint project arrangement would be a FERC-jurisdictional contract. SCE states that it would file a Permit to Construct application for the new Midpoint substation, as required by GO 131-D. SCE believes that the analysis in the joint EIR/EIS for the Desert Southwest project prepared by BLM and IID satisfies California's environmental requirements for the new substation, so that there would be no need to conduct any additional environmental review.

Neither SCE's PEA nor the Final EIR/EIS for DPV2 addressed environmental impacts that would occur if DPV2 were integrated with the Desert Southwest project with system upgrades that would increase the transfer capability of DPV2 above 1,200 MW. We view possible integration of DPV2 and the Desert Southwest project as speculative at this time, and find that the Final EIR/EIS addressed the Desert Southwest project adequately. However, we note that an increase in the transfer capability of DPV2 may have impacts such as increases in corona noise and EMF that were not addressed in the Final EIR/EIS. We do not authorize SCE to construct the Midpoint substation at this time. If SCE and IID reach agreement regarding integration of DPV2 and the Desert Southwest transmission project, SCE must address environmental and other impacts of the proposed upgrade to DPV2 in any filing requesting Commission authorization to construct the Midpoint substation.

B. Transmission Upgrades West of Devers Substation

1. Proposed Project

The "West of Devers" portion of the proposed DPV2 project would include upgrades to approximately 48 miles of 230 kV transmission lines west of the Devers substation. SCE would replace two existing 230 kV lines with a new double-circuit 230 kV line and would reconductor a third 230 kV line between the Devers substation and the San Bernardino Junction at the western end of San Timoteo Canyon. SCE would also reconductor a 230 kV transmission line between San Bernardino Junction and the Vista substation, and a 230 kV transmission line between San Bernardino Junction and the San Bernardino substation. SCE also proposes to install Special Protection Scheme relays at the Devers substation, the Padua substation in San Bernardino County, and the Vista substation in Riverside County.

The Final EIR/EIS concludes that the proposed 230 kV upgrades would have significant unmitigable impacts on cultural resources and air quality, which we discuss in Section IV.C as general impacts of the DPV2 project. At the same time, the proposed replacement of two existing 230 kV lines with a single double-circuit 230 kV line would improve views at viewpoints including Cedar Hollow Road in the City of Beaumont, Stargazer Street and Rose Avenue in the City of Beaumont, and the Oak Valley Golf Course in the City of Beaumont. Noise levels along the 230 kV lines would decrease because of the increased capacities of the new conductors and the reconfiguration of towers.

Some of the existing 230 kV transmission lines west of Devers that SCE proposes to upgrade cross over lands of the Morongo Band of Mission Indians (Morango Tribe) pursuant to existing right-of-way agreements that expire beginning in 2010. SCE reports that the Morango Tribe has informed SCE that continued use of the existing 230 kV transmission corridor after the current right-of-way agreements expire is not acceptable, but that the Morango Tribe is willing to negotiate regarding a new right-of-way corridor some distance from the existing 230 kV transmission lines. SCE expects that this new transmission corridor would cross less of the reservation and more privately-owned land.

Because of the Morango Tribe's opposition to the 230 kV upgrades over its land, SCE concludes that such upgrades are not feasible. SCE now recommends that the Commission authorize construction of the Devers-Valley No. 2 alternative.

2. Devers-Valley No. 2 Alternative

The Final EIR/EIS evaluates the Devers-Valley No. 2 alternative, a new 41.6-mile 500 kV line that would be constructed immediately adjacent to SCE's existing Devers-Valley No. 1's 500 kV transmission line, and primarily within existing easements. The route is adjacent to residential areas in the City of Banning and also in unincorporated portions of Riverside County including the Cabazon Estates area and the communities of Juniper Flat and Romoland. The route would traverse 4.7 miles of the Santa Rosa and San Jacinto Mountains National Monument (administered by BLM), approximately 1.9 miles of the San Bernardino National Forest, and the Potrero ACEC. It would cross the Pacific Crest National Scenic Trail, and the towers would be visible from the San Jacinto Wilderness Area.

Before the Devers-Valley No. 2 transmission line could be constructed, the Forest Service in the United States Department of Agriculture would have to determine whether it would be consistent with management direction in the governing Forest Plan. Based on Forest Service and BLM determinations, this alternative could require amendments to the San Bernardino National Forest Land Management Plan, the National Monument Proposed Management Plan, and an existing memorandum of understanding among BLM, the Forest Service, and the Pacific Crest Trail Association.

The Final EIR/EIS finds that the Devers-Valley No. 2 alternative would have significant unmitigable visual impacts because of the increased structural contrast, skylining, and view blockage along the corridor, and also from nearby areas including State Route 243, Mapes Road, and the community of Beaumont. The new transmission towers would increase significantly the amount of industrial development and diminish significantly the character and recreational value of the traversed and adjacent recreational resources. The Final EIR/EIS concludes that impacts to the Santa Rosa and San Jacinto National Monument, the Pacific Coast Trail, the San Bernardino National Forest, the San Jacinto Wilderness Area, and the Potrero ACEC would be significant and unmitigable.

3. Discussion

The Final EIR/EIS states that the West of Devers 230 kV upgrades are environmentally preferred over the Devers-Valley No. 2 alternative but that the Devers-Valley No. 2 alternative would be feasible to construct. The Final EIR/EIS concludes that, if the proposed West of Devers upgrades are found to be infeasible, the Devers-Valley No. 2 alternative would meet project objectives and would allow the entire DPV2 project to be constructed.

Because the Morango Tribe has informed SCE that the proposed upgrades to SCE's existing 230 kV transmission lines west of Devers are not acceptable, we agree with SCE that the West of Devers portion of SCE's proposed DPV2 project is not feasible. While it appears that the Morango Tribe may be amenable to an alternative transmission corridor across its land, such an alternative route has not been identified at this time. We do not know how long negotiations could take or, if SCE were to reach agreement with the Morango

Tribe, whether the agreed-upon transmission corridor over tribal land would be found acceptable after subsequent environmental review.

It is reasonable to authorize construction of the Devers-Valley No. 2 alternative. This would allow completion of the economically advantageous DPV2 project within the schedule proposed by SCE. With anticipated continued load growth in southern California, additional transmission upgrades west of Devers may be needed in the future. With authorization of the Devers-Valley No. 2 route, SCE and the Morango Tribe may continue to negotiate a new right-of-way agreement independent of DPV2.

C. General Environmental Impacts

1. Impacts on Cultural and Paleontological Resources

The Final EIR/EIS identifies several known archaeological sites eligible for listing on the National Register of Historic Places (National Register) that could be affected by DPV2 construction and operation, with additional potentially eligible cultural resource sites located within or adjacent to the transmission corridor. The Final EIR/EIS notes that some areas of direct impact, such as roads and temporary laydown areas, have not been specified or surveyed and that adverse effects to individual sites cannot be identified precisely until final tower locations are determined, detailed engineering plans for all project roads and facilities are completed, and final eligibility of cultural resources for the National Register has been assessed. Also, there is potential to encounter undiscovered cultural and paleontological resources, as well as buried Native American human remains. The Final EIR/EIS proposes several mitigation measures that would allow many direct impacts to be avoided through minor design modifications. The Final EIR/EIS concludes, however, that significant impacts may be unavoidable during project construction or operation.

2. Corona Noise Impacts

The Final EIR/EIS reports that addition of a second 500 kV line in the DPV1 and Devers-Valley No. 1 corridors would increase permanent noise levels and that the increased noise would create a significant and unmitigable impact at times along portions of the right of way. Specifically, the Final EIR/EIS finds that corona noise levels during wet weather and heavy line loads would violate Riverside County noise policies for residential and other noise-sensitive land uses within 25 feet of the 500 kV right of way.[15] SCE disputes this finding and asserts that it should not be required to mitigate DPV2's noise impacts.

Riverside County Noise Element Policy N.1.1 specifies that residential and other noise-sensitive land uses should be protected from high levels of noise by restricting or relocating noise sources, and Policy N.1.3 establishes a 65 CNEL[16] level as the appropriate trigger level for mitigation. The Final EIR/EIS describes that corona noise levels during wet weather and heavy line loads along the proposed Devers-Harquahala segment would increase to

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15 As described in Section IV.B.1, the 230 kV upgrades in SCE's West of Devers proposal would decrease noise levels along the 230 kV rights of way.

16 The CNEL, or community noise equivalent level, measures the aggregated sound level occurring over a 24-hour period in decibels (dBA), with a 5 dBA penalty added to evening sounds (between 7:00 p.m. and 10:00 p.m.) and a 10 dBA penalty added to night-time sounds (between 10:00 p.m. and 7:00 a.m.).

about 65.7 Ldn[17] at the edge of the right of way. It concludes that the Riverside County noise policy would be violated during those times for residential uses within 25 feet of the right of way. While noise studies were not provided for the Devers-Valley alternate route, the Final EIR/EIS concludes that the Riverside County noise policy would likely be violated similarly during wet weather and heavy load conditions along the Devers-Valley corridor.

The Final EIR/EIS identifies that the proposed Devers-Harquahala 500 kV line would be located approximately 100 feet from two or three residences in the Palo Verde Valley west of Blythe in California and also would be adjacent to residences in the communities of Thousand Palms and North Palm Springs. The Devers-Valley 500 kV route is adjacent to residential areas in the City of Banning and in unincorporated portions of Riverside County including the Cabazon Estates area, the community of Juniper Flats, areas south of Banning, and areas near the community of Romoland. The Final EIR/EIS did not identify any structures within 25 feet of the right of way, but the identified noise impacts are presumed to occur in the outdoor areas of the residential properties.

SCE contests the finding in the Final EIR/EIS that the DPV2 corona noise level would conflict with the Riverside County noise ordinance. SCE states that the method relied upon in the draft EIR/EIS is based on the L5 noise level (the volume of sound exceeded 5% of the time). SCE reports that, for recent utility projects, Riverside County has applied the CNEL process based on the L50 noise level (the volume of sound exceeded 50% of the time) rather than the L5

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[17] The Ldn, or day-night sound level, is a metric similar to CNEL, but it is less stringent because it omits the 5 dBA penalty that the CNEL measurement applies to evening sounds.

noise level. SCE submits that use of the DPV2 project's L50 noise level of 54.7 dBA results in a CNEL noise level of 61.4 dBA, below the 65 dBA threshold in the Riverside County noise ordinance. While SCE has raised questions regarding the manner in which Riverside County interprets its noise ordinance, we are not convinced that the finding in the Final EIR/EIS regarding the significant impact of whether corona noise associated with DPV2 should be rejected.

The Final EIR/EIS states that there are few options for mitigating corona noise as it is a function of conductor design and configuration. The Final EIR/EIS describes that SCE would be expected to properly handle the conductor during construction to avoid damage that could undermine the load-carrying capability of the line and exacerbate the corona effect. The Final EIR/EIS does not recommend that SCE be required to purchase or relocate residences, or undertake any other actions to mitigate corona noise impacts.

SCE asserts that the Final EIR/EIS misrepresents that SCE plans to use APM L-7, an applicant-proposed mitigation measure, to mitigate corona noise. APM L-7, included in SCE's PEA, states as follows:

> Link 10 crosses an (unoccupied) single-family dwelling unit at Milepost 5.3. Two additional single-family dwelling units and one mobile home would be impacted due to the alignment of Link 10 at Milepost 6.2. Mitigation measures would include purchase of the parcel and relocation or, if practical, adjusting the transmission line alignment and placing towers to avoid the affected dwelling units.

SCE explains that it suggested APM L-7 as a land-use mitigation measure only because DPV2 may cross over 4 residential parcels, such that SCE may have to purchase the properties or exercise its powers of eminent domain. SCE did not mean that it would relocate homeowners to mitigate corona noise.

SCE asserts that the Commission should not require SCE to relocate homeowners due to corona noise and, further, that such homeowners may not want to be relocated.

We are persuaded that APM L-7 is relevant to noise impacts only to the extent that, because SCE plans to purchase or relocate dwelling units that DPV2 would cross over otherwise, the identified noise problem would no longer exist for those dwelling units. We see no need to clarify APM L-7 in this regard, as SCE suggests.

3. Air Quality Impacts

Assessment of air quality impacts requires that emissions for the entire DPV2 project be evaluated within each of the affected jurisdictions and/or air basins. As a result, the Final EIR/EIS presents its air quality assessment by jurisdiction rather than by project segment.

The Final EIR/EIS describes expected dust and exhaust emissions during DPV2's construction and operation. With mitigation measures, dust and exhaust emissions during construction would remain below the significance thresholds in areas within the jurisdiction of the Maricopa County Air Quality Department, the Air Quality Division of the Arizona Department of Environmental Quality, and the Mojave Desert Air Quality Management District.

While most of the proposed DPV2 route through the South Coast Air Quality Management District (SCAQMD) in southern California is in remote areas, the western part of the route is in more highly developed areas. In this urban context, SCAQMD experiences more severe baseline air quality nonattainment than the other jurisdictions affected by the proposed DPV2 project. The Final EIR/EIS reports that, even with the recommended mitigation measures, construction emissions would exceed the SCAQMD daily regional significance criteria and, thus, would cause significant and unavoidable (Class I) impacts in the SCAQMD. The Final EIR/EIS makes comparable findings regarding construction impacts of the Alligator Rock, Devers-Valley, and Desert Southwest alternatives, which would be located wholly (Alligator Rock and Devers-Valley alternatives) or partially (Desert Southwest) within the SCAQMD jurisdiction.

The Final EIR/EIS describes that power generated during DPV2 operation would cause emissions from power plants. The CAISO forecasts that, with DPV2, NOx emissions from power plants in Arizona would increase by 200 tons per year and that NOx emissions in California would decrease by 590 tons per year, for a net decrease of 390 tons per year. Similar changes in emissions of other criteria pollutants related to power generation would also occur. The CAISO's assessment is based on 2008 conditions at existing power plants that the CAISO determined to be underutilized in the absence of DPV2. The precise location and quantity of the emissions would change over time depending on the ultimate sources of power flowing into DPV2.

The Final EIR/EIS describes that the identified increase in power plant emissions in Arizona represents an increase of 0.05% of Arizona statewide 2001 NOx emissions and would be within permitted emission levels that have been licensed previously by local air management agencies. The Final EIR/EIS concludes that the increase in power plant emissions in Arizona would be an adverse but less than significant impact of DPV2. The forecasted decrease in California power plant emissions would be a beneficial impact of the proposed project.

V. EMF Issues

The Commission first established EMF policies in D.93-11-013. In our recent review of EMF issues, the Commission stated in D.06-01-042 that, "at this time we are unable to determine whether there is a significant scientifically verifiable relationship between EMF exposure and negative health consequences." We affirmed in D.06-01-042 that the Commission's EMF policy is one of prudent avoidance, with application of low-cost/no-cost mitigation measures to reduce EMF exposure for new and upgraded utility transmission and substation projects. The Commission has adopted a benchmark of 4% of total project cost for low-cost EMF mitigation measures, with flexibility to allow expenditures above the 4% benchmark if justified by a project's unique circumstances. In D.06-01-042, the Commission stated that, as a guideline, low-cost EMF mitigation measures should reduce EMF levels by at least 15% at edge of the utility right of way.

The Final EIR/EIS provides information regarding EMF associated with DPV2. It does not consider magnetic fields[18] in the context of CEQA or NEPA and the determination of environmental impacts because there is no agreement among scientists that EMF creates a potential health risk and because there are no defined or adopted CEQA or NEPA standards for defining health risk from EMF.

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[18] Because electric fields are shielded effectively by materials such as trees and walls, the emphasis in the Commission's consideration of EMF is on exposure to magnetic fields.

A. EMF Along Routes Under Consideration

Along the edge of the right of way for the existing DPV1 line, magnetic fields currently range from 8.3 milliGauss (mG) in Riverside County near Thousand Palms to 72.9 mG in Copper Bottom Pass in the Dome Rock Mountains in Arizona. With the addition of DPV2 along the Devers-Harquahala segment, field levels are expected to be reduced between 0.8 and 37.9 mG on the side of the right of way where the existing DPV1 line is located. On the side of the right of way where the new line would be installed, magnetic field levels would increase up to 30.0 mG.

Alternative route segments evaluated for the Devers-Harquahala line are all 500 kV and, if the alternative is adjacent to an existing 500 kV circuit, they would involve field levels similar to those for the proposed Devers-Harquahala route. For alternatives that would require a 500 kV line in a new corridor, magnetic field levels would range between 11.2 and 46.5 mG at the edge of the right of way.

For the 230 kV transmission lines proposed to be upgraded west of the Devers substation, existing magnetic fields at the edge of the right of way range from 4.1 mG in Grand Terrance to 38.5 mG in the Loma Linda area. If the 230 kV upgrades were constructed, field levels would be reduced at the edge of the right of way between 1.0 and 18.1 mG below the existing levels.

The Devers-Valley No. 2 500 kV alternative would be constructed adjacent to the existing Devers-Valley No. 1 500 kV line. Baseline magnetic fields range between 14 and 63 mG at the edge of the right of way. With installation of the second transmission line, magnetic fields would increase between 22 and 28 mG on the side where the new line would be installed and fields would decrease between 16 and 19 mG on the side where the existing line is located.

B. EMF Management Plan for DPV2

SCE states that it has incorporated low-cost and no-cost measures to reduce magnetic fields along the proposed DPV2 route. For the 500 kV Harquahala-Devers line, SCE proposes to optimally phase the DPV2 line with DPV1, as a no-cost EMF mitigation measure. With optimal phasing, adding the DPV2 line to the DPV1 corridor will increase magnetic fields on the side of the right of way adjacent to the new line and decrease magnetic fields on the other side of the right of way as described above. However, the proposed optimal phasing would reduce the fields compared to what they would be if DPV2 were constructed without this EMF reduction measure.

For the 230 kV upgrades proposed west of the Devers substation, SCE proposes to optimally phase the 230 kV lines, as a no-cost EMF mitigation measure, and to optimally phase adjacent 55 kV lines between San Bernardino substation and San Bernardino Junction as a low-cost measure estimated to cost $270,000. As described above, these no-cost and low-cost measures would reduce the magnetic fields on both sides of the 230 kV right of way.

The ALJ requested that SCE develop information regarding the feasibility of low-cost mitigation of magnetic fields associated with the 500 kV Devers-Harquahala line and the 500 kV Devers-Valley No. 2 alternative to the 230 kV West of Devers upgrades. In particular, SCE was asked to determine how much taller the 500 kV towers would need to be in order to reduce magnetic fields by 15% at the edge of the right of way closer to the new transmission line, which is the side where DPV2 would increase the magnetic fields. The request was limited to those locations where there are residences within 200 feet of that edge of the right of way.

In response to the ALJ request and based on information compiled for the environmental review, Energy Division identified 60 residences within 200 feet of the right of way on the side closer to the new 500 kV transmission lines, with 5 residences located along the Devers-Harquahala segment and the remaining 55 residences located along the Devers-Valley segment. SCE reported that achievement of a 15% reduction in the magnetic field at the edge of the right of way near these residences would require a 20-foot increase in the height of about 33 towers, at an estimated incremental cost of $1.4 million. Since tower designs have height limitations, SCE cautions that, if any proposed tower height is already taller than about 170 feet, the additional 20-foot height increase may require a different tower design, with potentially significant cost increases.

SCE recommends that the Commission not require this low-cost EMF mitigation, but instead allow the tower and conductor heights to match the adjacent 500 kV transmission lines. SCE submits that constructing new towers taller than the existing towers would increase visual impacts and would conflict with recommended mitigation measures aimed at reducing the visual contrast of the towers, in particular, requirements that new towers match the heights of existing towers to the extent possible. SCE argues further that taller towers would increase the potential for collisions of birds with the power lines, and would conflict with recommended mitigation measures that would require that new towers and lines not be located significantly above existing towers and lines as a collision-reduction technique. As additional support for its position, SCE reports that, while 20-foot higher towers would reduce the magnetic field level by 15% at the edge of the right of way, magnetic field level changes beyond 50 feet from the edge of the right of way would be insignificant.

C. Discussion

As discussed in Section IV.B, we authorize SCE to construct the Devers-Valley No. 2 500 kV transmission line instead of the 230 kV transmission upgrades west of the Devers substation. With that modification to the DPV2 project, SCE should amend its EMF management plan as needed to apply its no-cost 500 kV EMF management techniques to the Devers-Valley corridor in addition to the Devers-Harquahala corridor.

Consistent with D.06-01-042 and D.93-11-013, we require that SCE undertake low-cost EMF mitigation. SCE should increase tower and conductor heights by 20 feet along those portions of the transmission corridor where there are residences near the side of the right of way closer to the new 500 kV transmission lines. SCE has established that this design modification would reduce magnetic fields by 15% at the edge of the right of way, which is consistent with the Commission's guidance in D.06-01-042 for low-cost EMF mitigation. This design modification should be undertaken wherever there are residential properties within 50 feet of the side of the right of way closer to the new 500 kV transmission lines. As SCE has pointed out, the change in magnetic field strength due to the new transmission lines would decrease significantly beyond 50 feet from the right of way.

We do not believe that the potential conflict of this low-cost EMF mitigation measure with environmental mitigation efforts would be significant. Few of the areas where EMF mitigation will occur are completely flat, and the towers and conductors would be difficult to line up due to even small elevation changes between existing and new towers. With tower heights of 150 feet, a 20-foot height increase for DPV2 towers and conductors is unlikely to be noticeable to most observers.

We require that SCE apply this low-cost EMF mitigation measure where there are existing residential properties and also where development of new residences is underway at the time that SCE undertakes final DPV2 project design. Consistent with guidance in D.06-01-042, we do not require that SCE attempt to determine possible future uses of undeveloped land. If applicable, SCE would not be required to raise tower heights near residential properties that will be acquired and converted from residential use in order to allow construction of DPV2, for example, as contemplated by APM L-7 (see Section IV.C.2 above).

With limitation to areas where residential properties are within 50 feet of the edge of the right of way closer to the new 500 kV transmission lines, the cost of the adopted EMF mitigation measure may be less than SCE's $1.4 million estimate, which encompassed residential properties within 200 feet of the right of way. Even at $1.4 million, the cost will be much less than the Commission's 4% benchmark for low-cost EMF mitigation. As described in Section III.A.5, SCE may seek an increase in the approved maximum cost of DPV2 if the adopted low-cost EMF mitigation measure causes the cost cap to be exceeded.

VI. Environmental Analysis

A. Mitigation Measures

The conclusions in the Final EIR/EIS regarding environmental impacts of the proposed project and its alternatives assume that the impact-reduction measures proposed in the PEA, called Applicant Proposed Measures or APMs, and the additional mitigation measures recommended in the Final EIR/EIS will be implemented. In Section IV.C.2, we address SCE's concerns with interpretation of APM L-7. In this section, we address two additional concerns about mitigation measures. We adopt the mitigation measures proposed in the

Final EIR/EIS. The applicable Applicant Proposed Measures and Final EIR/EIS mitigation measures for DPV2 are included in Attachment A. Implementation of the Applicant Proposed Measures and the applicable mitigation measures is a condition of our approval of this project.

1. Raven Control

In its Phase 2 brief, SCE takes issue with one of the Final EIR/EIS mitigation measures, specifically, mitigation measure B-16a regarding raven control.[19] In addition to SCE's APM B-20 requiring that transmission lines be designed to reduce the likelihood of nesting by common ravens and removal of any common raven nests found on the structures, the Final EIR/EIS recommends mitigation measure B-16a, as follows:

B-16a **Prepare and implement a raven control plan.** SCE shall prepare a common raven control plan that identifies the purpose of conducting raven control, provides training in how to identify raven nests and how to determine whether a nest belongs to a raven or a different raptor species, describes the seasonal limitations on disturbing nesting raptors species (excluding ravens), describes the procedure for obtaining a permit from the USFWS's Division of Migratory Birds, and describes procedures for documenting the activities on an annual basis. SCE shall gain approval of the plan from the USFWS's Division of Migratory Birds. SCE shall provide this raven control plan to all transmission line companies that conduct operations within the [right of way].

SCE requests that mitigation measure B-16a be modified as follows:

B-16a **Contribute to an agency sponsored raven reduction plan for the California desert.** SCE will work with the Bureau of Land

[19] Common ravens are known to nest in transmission towers and prey upon nearby wildlife species, including juvenile tortoises and other wildlife species that may be listed as threatened or endangered, or considered sensitive.

> Management and the USFWS to reduce raven populations in the desert by contributing to an agency-sponsored raven reduction program for the California Desert. The amount of contribution shall be commensurate with the expected contribution of raven nesting resulting from the DPV2 transmission line.

SCE expresses concern that mitigation measure B-16a as presented in the Final EIR/EIS would be infeasible, with unlimited scope and expenditure. SCE states that the Commission should not impose mitigation measures to be applied to existing transmission lines, or to other transmission owners. It contends that there likely would be no reduction in raven nesting activity by removing raven nests from towers on DPV2 when there is no raven control on the adjacent towers. SCE also questions the feasibility of raven control, citing its experience that ravens often will rebuild a nest as soon as it is taken down. SCE suggests that it could make a monetary contribution to an agency-sponsored raven reduction program, requesting that, at a minimum, the Commission revise mitigation measure B16-a "to place some reasonable limitations on what SCE could be required to do for this program."

Mitigation measure B-16a as recommended in the Final EIR/EIS would require that SCE develop a raven control plan for its own use and provide a copy to other transmission companies. We are perplexed by SCE's contention that this mitigation measure may not provide any benefits, in light of its own proposed measure for raven control and nest removal in APM B-20. The efficacy of SCE's proposed revision to mitigation measure B-16a is questionable. BLM and the USFWS have not indicated that they have, or are interested in creating, an agency-sponsored raven reduction program for the California desert. We adopt mitigation measure B-16a as proposed in the Final EIR/EIS.

2. Agua Caliente Allottee Land

SCE's Devers-Palo Verde right of way crosses an approximately 0.1-mile stretch of land held by members of the Agua Caliente Band of Cahuilla Indians (Agua Caliente). During the DPV2 environmental review, Agua Caliente submitted a letter to the Commission and BLM asserting jurisdiction over the land and requesting that a mitigation measure be imposed requiring that SCE obtain a conditional use permit prior to construction of DPV2.

SCE asserts that it is not required to obtain a conditional use permit for this land. SCE states that it is consulting and coordinating with the Agua Caliente Planning Department regarding the right of way, but that it objects to the proposed terms of a conditional use permit, which would last no more than 25 years and may be revoked.

As explained in the Final EIR/EIS, the Commission has preemptive jurisdiction over the construction, maintenance, and operation of SCE facilities in California. However, GO 131-D requires SCE to comply with local building, design, and safety standards to the greatest degree feasible to minimize project conflicts with local concerns. Section XIV of GO 131-D provides that, where the utility and a local jurisdiction are unable to reach agreement on a utility project, the utility may bring the conflict before the Commission for resolution. Mitigation measure L-1c in the Final EIR/EIS mirrors the provisions of GO 131-D.

The Agua Caliente opposed SCE's use of this allottee land when it constructed DPV1. The Commission authorized SCE to obtain a right of way through the land, and SCE successfully litigated an eminent domain complaint in federal district court pursuant to 25 U.S.C. § 357 to condemn the allottee land needed for DPV1.[20]

We find that mitigation measure L-1c addresses the Agua Caliente concerns adequately. SCE should negotiate in good faith to reach a mutually acceptable agreement with the allotee and should coordinate with the Agua Caliente. If the parties are unable to reach an agreement, SCE should follow the procedures in GO 131-D and mitigation measure L-1c to obtain further Commission review of the dispute.

B. Mitigation Monitoring

The Final EIR/EIS includes a proposed Mitigation Monitoring, Compliance, and Reporting Program (MMCRP or Mitigation Monitoring Program) for the mitigation measures it recommends for the DPV2 project. It recommends a framework for implementation of the Mitigation Monitoring Program by this Commission as the CEQA lead agency and BLM as the NEPA lead agency. We adopt the Mitigation Monitoring Program.

Consistent with Public Resources Code § 21081.6 and CEQA Guidelines § 15097, the Commission must adopt a Mitigation Monitoring Program when it approves a project that is subject to preparation of an EIR and where the EIR identifies significant adverse environmental effects. As the NEPA lead agency, BLM is responsible for ensuring that mitigation measures are implemented on its land. In the memorandum of understanding between BLM and the Commission governing the joint environmental review of DPV2, BLM and the Commission

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[20] Southern California Edison Co. v. Rice, 685 F.2d 354, 1982 U.S. App. LEXIS 16318 (9th Cir. Cal. 1982) petition for cert. denied, Rice v. Southern California Edison, 460 U.S. 1051, 103 S. Ct. 1497, 75 L. Ed. 2d 929, 1983 U.S. LEXIS 4300, 51 U.S.L.W. 3703 (1983).

have agreed that the Commission will be responsible for implementing all adopted mitigation and monitoring provisions on both State and federal lands. BLM has agreed to provide the Commission access to federal lands as needed to conduct the adopted mitigation and monitoring activities.

C. Adequacy and Certification of the Final EIR/EIS

The Final EIR/EIS must contain specific information according to the CEQA guidelines, §§ 15120 through 15132. The various elements of the Final EIR/EIS satisfy these CEQA requirements. The Final EIR/EIS consists of the draft EIR/EIS, with revisions in response to comments and other information received. Volume 3 of the Final EIR/EIS contains the comments received on the draft EIR/EIS and individual responses to these comments.[21]

The Commission must conclude that the Final EIR/EIS is in compliance with CEQA before approving SCE's request for a CPCN. The basic purpose is to ensure that the environmental document is a comprehensive, accurate, and unbiased tool to be used by the lead agency and other decisionmakers in addressing the merits of the project. The document should embody "an interdisciplinary approach that will ensure the integrated use of the natural and social sciences and the consideration of qualitative as well as quantitative factors."[22] It must be prepared in a clear format and in plain language.[23] It must be analytical rather than encyclopedic, and emphasize alternatives over

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[21] CEQA Guidelines, § 15132.

[22] *Id.*, § 15142.

[23] *Id.*, §§ 15006(q) and (r), 15120, 15140.

unnecessary description of the project.[24] Most importantly, it must be "organized and written in such a manner that [it] will be meaningful and useful to decisionmakers and the public."[25]

We believe that the Final EIR/EIS meets these tests. It is a comprehensive, detailed, and complete document that discusses clearly the advantages and disadvantages of the environmentally superior routes, SCE's proposed route, and various alternatives. We find that the Final EIR/EIS is a competent and comprehensive informational tool, as CEQA requires it to be. The quality of the information in the Final EIR/EIS is such that we are confident of its accuracy, except that we find that Section H.1.3 in the Mitigation Monitoring and Reporting section should be deleted. We have considered the information in the Final EIR/EIS in approving the DPV2 project as described in this decision. The Commission should certify the Final EIR/EIS with Section H.1.3 deleted.

VII. Authorized DPV2 Project and Statement of Overriding Considerations

A. Authorized DPV2 Project

Based on the considerations above, we authorize SCE to construct the proposed DPV2 project with the following routing conditions:

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[24] *Id.*, §§ 15006, 15141; Pub. Res. Code § 21003(c).

[25] Pub. Res. Code § 21003(b).

> SCE should terminate DPV2 at a new Harquahala Junction, if a commercially reasonable agreement can be reached and subject to approval by the Arizona Corporation Commission and any other needed authorizations. Otherwise, SCE may terminate DPV2 at the Harquahala switchyard.
>
> SCE may construct a route in the Kofa area that is acceptable to the USFWS and other permitting agencies.
>
> SCE should construct the North of Desert Center alternative in the Alligator Rock ACEC area if BLM authorizes this route. Otherwise, SCE may build DPV2 on a route segment through the Alligator Rock ACEC area acceptable to BLM, if the segment received full consideration in the Final EIR/EIS or deviates from one of the reviewed route segments solely within BLM land.
>
> SCE should construct the Devers-Valley No. 2 500 kV alternative rather than the 230 kV upgrades that SCE proposed west of the Devers substation.

Attachment B presents the findings required by CEQA Guidelines Section 15091, describing each significant and potentially significant impact identified in the Final EIR/EIS, the relevant mitigation measures, and the findings of the Commission with respect to each impact.

The Final EIR/EIS has identified unavoidable significant impacts that will result from construction and operation of the authorized DPV2 project. Section 15093(b) of the CEQA Guidelines provides that, when the decision of the public agency allows the occurrence of significant impacts which are identified in the EIR but are not at least substantially mitigated, the agency must state in writing the reasons to support its action based on the completed EIR and/or other information in the record. CEQA Guidelines Section 15093(b) requires that the decision-maker adopt a Statement of Overriding Considerations at the time of approval of the project if it finds that significant adverse environmental effects have been identified in the EIR that cannot be substantially mitigated to an insignificant level or be eliminated.

The following impacts are not mitigated to a less than significant level for the proposed project: visual impacts in Kofa (Arizona), Harquahala Mountain Telecommunication Facility (Arizona), and the Alligator Rock ACEC); wilderness/recreation effects at the same three locations and also at the Chuckwalla Dune Thicket ACEC; the conversion of agricultural land to non-agricultural use (13.6 acres in Arizona); potential adverse changes to known historic resources, to buried prehistoric and historical archaeological sites, or to human remains; corona noise that would exceed Riverside County standards; and air emissions that would exceed thresholds in the SCAQMD.

Implementation of alternatives could eliminate some of these identified impacts. Use of the North of Desert Center alternative to avoid new impacts to the Alligator Rock ACEC would eliminate visual, wilderness/recreation, and cultural resources impacts to the ACEC, but would create additional visual impacts resulting from the addition of the transmission line in a new corridor north of the ACEC. Implementation of the Harquahala Junction Switchyard alternative would eliminate the significant impact from conversion of agricultural lands in Arizona. While a wide range of alternatives was evaluated in an attempt to avoid impacts to Kofa, no feasible alternatives were identified that would reduce impacts in comparison with the impacts of the proposed project.

In the project segment west of the Devers substation, the proposed West of Devers upgrades would not create any significant unmitigable impacts. Since the Morongo Tribe has informed SCE that its proposed West of Devers upgrades are not acceptable, this portion of the project is not feasible, and we authorize construction of the Devers-Valley No. 2 alternative. This alternative would have the following significant and unmitigable impacts: visual impacts in several locations; inconsistency with BLM's Visual Resources Methodology management objectives in the Potrero ACEC and with the San Bernardino National Forest's Scenic Integrity Objectives; wilderness/recreation impacts at Santa Rosa and San Jacinto Mountains National Monument, Pacific Crest Trail, San Jacinto Wilderness Area, and Potrero ACEC; potential adverse changes to known historic resources, to buried prehistoric and historical archaeological sites, or to human remains.; corona noise; and air emissions.

None of the other alternatives alleviate the significant impacts and are feasible in light of the project objectives, as described in Final EIR/EIS Appendix 1 (Alternatives Screening Report). Accordingly, the Commission adopts the following Statement of Overriding Considerations.

B. Statement of Overriding Considerations

The Commission recognizes that significant and unavoidable impacts will result from implementation of the DPV2 project. Having (i) adopted all feasible mitigation measures, (ii) adopted certain alternatives that reduce the impacts of the proposed project, (iii) rejected as infeasible alternatives to the project discussed above, (iv) recognized all significant, unavoidable impacts, and (v) balanced the benefits of the project against the project's significant and unavoidable impacts, the Commission hereby finds that the benefits outweigh and override the significant unavoidable impacts for the reasons stated below.

The Commission adopts and makes this statement of overriding considerations concerning the DPV2 project's unavoidable significant impacts to explain why the project's benefits outweigh its unavoidable impacts.

The discussion above and in Sections III and IV describes each alternative that was considered in the Final EIR/EIS and explains why each one has been included in the authorized project or rejected.

This project will provide substantial benefits, in that it will provide significant economic benefits for CAISO ratepayers, increase the reliability of the interstate transmission network, increase operational flexibility, and provide insurance value as an economic hedge against low-probability, high-impact events. We set forth the reasons for finding these substantial benefits, with citations to the record, in Section III above. The Commission finds that the DPV2 project's unavoidable impacts are acceptable in light of these substantial benefits, which constitute an overriding consideration warranting approval of the project, despite each and every unavoidable impact.

VIII. Compliance with Public Utilities Code Section 625

Pub. Util. Code § 625 provides that a public utility that offers competitive services may not condemn any property for the purpose of competing with another entity unless the Commission finds that such an action would serve the public interest based on a hearing for which the owner of the property to be condemned has been noticed and the public has an opportunity to participate (§ 625(a)(1)(A)). However, an exception is made for condemnation actions that are necessary solely for an electric or gas company to meet a Commission-ordered obligation to serve. In that circumstance, the electric or gas company is required to provide notice on the Commission Calendar if and when it pursues installation of facilities for the purpose of providing competitive services (§ 625(a)(1)(B)).

SCE proposed the DPV2 project to meet SCE's obligation to serve its electric customers, and we authorize it for that purpose. The DPV2 project includes new fiber optic cable to provide internal communications links for line protection, but SCE states that it has no current intention to use this fiber optic cable for competitive purposes or to lease it.

In D.01-10-029, the Commission addressed the applicability of § 625 where the utility is implementing a project to meet its obligation to serve, but aspects of the project may have a competitive purpose later. We described that § 625 provides two different levels of notice and oversight and that, "The lesser standard requires that when condemning properties to carry out a commission-ordered obligation, § 625(a)(1)(B) is applicable, which only requires notice be provided to the Commission Calendar." With similar circumstances, we conclude as in D.01-10-029 that the lesser standard, notice, applies for the DPV2 project.

IX. SCE Motion Regarding DRA Consultant Costs

On August 30, 2006, SCE filed a motion regarding reimbursement of DRA consultant expenses. SCE asks the Commission to do the following:

1. Find that SCE should reimburse DRA up to $375,000 for consultant expenses incurred for this proceeding, consistent with § 631;

2. Authorize SCE to capitalize the reimbursed consultant costs as project costs, and adjust the adopted cost cap by the final amount;

3. Allow SCE to provide the final amount in a filing it would make after the issuance of the CPCN in this proceeding;

4. Account for DRA consultant costs related to the DPV2 project separately from those consultant costs related to I.05-06-041; and,

5. If the Commission deems it appropriate to have DRA reimbursed for its consultant costs related to I.05-06-041, order that such consultant costs be allocated to PG&E and SDG&E as well as SCE.

DRA filed a response to SCE's motion. Regarding SCE's first request, DRA does not believe a Commission finding is required, since SCE does not dispute that it must reimburse DRA's consultant costs related to this case. DRA does not object to SCE's proposal that reimbursed costs be included in the cost cap and capitalized.

DRA takes issue with SCE's assertion that some of DRA's consultant work related solely to I.05-06-041 and therefore is not reimbursable pursuant to § 631. DRA states that its consultants were engaged to provide expert testimony on the need for DPV2 and that all prepared testimony fell within that scope. DRA states that, since the Phase 1 hearings were held jointly in A.05-04-015 and I.05-06-041, the hearing time could be considered a joint activity. It maintains, however, that DRA's consultants attended the hearings only to address the need for DPV2. DRA concludes that its consultant costs should not be separated into two categories as SCE suggests, and instead should all be reimbursed pursuant to § 631.

PG&E responded in opposition to SCE's suggestion that a portion of DRA's consultant costs could be allocated to PG&E. PG&E argues that there is no basis for it or its ratepayers to assume any of the costs associated with DRA's consultants.

We agree with SCE that DRA consultants' evaluation of DPV2 assisted in the Commission's concurrent consideration in I.05-06-041 of methodologies for the economic evaluation of transmission lines. However, a review of the consultants' testimony confirms, as DRA indicates in its response, that their evaluation focused on need for DPV2. We find that the issues addressed by DRA's consultants are inextricably linked to the Commission's review of DPV2. For this reason, SCE should reimburse all of DRA's consultant costs in this proceeding, pursuant to § 631. We will not place a $375,000 limit on the reimbursable amount, as SCE requests.

We reject SCE's request that the cost cap for DPV be increased to reflect DRA's consultant costs. SCE has included an allowance for contingency costs in its DPV2 cost estimates, which we include in the maximum cost adopted in Section III.A.5.b pursuant to § 1005.5(a). SCE may treat the reimbursed consultant costs as DPV2 project costs for purposes of determining compliance with the approved maximum cost. If needed, SCE may seek an increase in the approved maximum cost as provided in Section 1005.5(b).

DRA notes that, at the time of its response to SCE's motion, DRA had presented SCE five invoices and eight late notices for costs related to DRA's consultants, in amounts exceeding $300,000. SCE should pay all outstanding DRA invoices within five days of the effective date of this order.

X. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on ________________, and reply comments were filed on ____________.

XI. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner and Charlotte F. TerKeurst is the assigned ALJ in this proceeding.

Findings of Fact

1. Our assessment of the economic benefits the DPV2 project is based on its design and construction to provide 1,200 MW of transfer capability between southern California and Arizona, to be operated by the CAISO.

2. SCE projects that DPV2 will provide benefits to CAISO ratepayers of almost $460 million in excess of its costs, with a resulting benefit-cost ratio of 1.71.

3. The CAISO projects that DPV2 will provide levelized annual benefits to CAISO ratepayers between $17 million and $158 million in excess of its costs, with a resulting benefit-cost ratio between 1.25 and 3.34.

4. DRA forecasts that DPV2 will provide net energy benefits of $261 million in excess of DPV2's costs, with a CAISO Ratepayer benefit-cost ratio of 1.31.

5. It is reasonable to adopt a maximum cost for DPV2 pursuant to § 1005.5(a) of $545,285,000 in 2005 dollars, to be decreased by $24,080,000 if the Devers-Harquahala line is terminated at Harquahala Junction and increased by $8,282,000 if the Alligator Rock—North of Desert Center route segment is used. In assessing compliance with the authorized maximum cost, it is reasonable to deflate actual expenditures to their equivalent value in 2005 dollars using the Handy-Whitman Index of Public Utility Construction Costs.

6. The parties' economic evaluations of DPV2 submitted in this proceeding demonstrate that DPV2 will provide significant economic benefits to CAISO-area ratepayers.

7. DPV2 will expand the interstate regional transmission network, increase its reliability, provide more operational flexibility, and provide insurance value as an economic hedge against low-probability, high-impact events.

8. Energy efficiency, demand response, and renewable generation do not hold sufficient near-term promise to provide a feasible or cost-effective alternative to DPV2, and would not offer the operational and other system benefits expected due to DPV2.

9. New transmission and generation options, in addition to demand side resources, should be pursued to meet the need for new energy supply in southern California.

10. Based on the STEP process that considered a range of potential transmission alternatives, DPV2 is the preferred new transmission alternative to provide access to lower-cost energy in the Southwest.

11. Terminating the Devers-Harquahala transmission line at Harquahala Junction would be less expensive than termination at the Harquahala Generating Company switchyard, and is the environmentally preferred alternative.

12. It is reasonable to require SCE to pursue good-faith efforts to reach a commercially reasonable agreement and seek the additional authorizations needed for construction of Harquahala Junction.

13. The Alligator Rock—North of Desert Center alternate route segment would avoid the Alligator Rock ACEC and is environmentally preferable to the proposed project paralleling DPV1 through the ACEC.

14. Neither SCE's PEA nor the Final EIR/EIS for DPV2 addressed environmental impacts if DPV2 is integrated with the Desert Southwest project.

15. The Devers-Valley No. 2 alternative is a viable and acceptable alternative to the West of Devers upgrades proposed by SCE.

16. It is reasonable to allow SCE to construct the Devers-Valley No. 2 transmission line as part of the DPV2 project.

17. A 20-foot increase in the height of DPV2 transmission towers would achieve a 15% reduction in the magnetic field at the edge of the right of way nearest to the DPV2 towers.

18. SCE reports that increasing the height of 33 towers by 20 feet would have an incremental cost of $1.4 million.

19. It is reasonable to require SCE to undertake low-cost EMF mitigation for the DPV2 project, as described in Section V.C of this decision.

20. A comprehensive record on environmental matters was developed in this proceeding through issuance of a draft EIR/EIS, consultation with public agencies and others, and public hearings. All are elements in the environmental process, which culminated in the issuance of the Final EIR/EIS.

21. The project alternatives considered in the Final EIR/EIS constitute a reasonable range of feasible alternatives, as required by the CEQA Guidelines.

22. The Final EIR/EIS identifies significant environmental impacts of the approved route that cannot be mitigated or avoided.

23. The environmental mitigation measures identified in the Final EIR/EIS and contained in Attachment A, are feasible and will minimize or avoid significant environmental impacts.

24. As State lead agency under CEQA, the Commission is required to monitor the implementation of mitigation measures adopted for this project to ensure full compliance with the provisions of the monitoring program.

25. The Mitigation Monitoring, Compliance, and Reporting Plan in Section X of Attachment B to this decision conforms to the recommendations of the Final

EIR/EIS for measures required to mitigate or avoid environmental effects of the project that can be reduced or avoided.

26. The Commission will develop a detailed implementation plan for the Mitigation Monitoring, Compliance, and Reporting Plan.

27. The Commission has reviewed and considered the information in the Final EIR/EIS before approving the project.

28. The Final EIR/EIS is a competent and comprehensive informational tool. With deletion of Section H.1.3, the quality of the information therein is such that we are confident of its accuracy.

29. Statement of Overriding Considerations: The DPV2 project will provide substantial benefits, in that it will provide significant economic benefits for CAISO-area ratepayers, increase the reliability of the interstate transmission network, increase operational flexibility, and provide insurance value as an economic hedge against low-probability, high-impact events. The DPV2 project's unavoidable impacts are acceptable in light of these substantial benefits, which constitute an overriding consideration warranting approval of the project, despite each and every unavoidable impact.

Conclusions of Law

1. The Commission has jurisdiction over the proposed project pursuant to, *inter alia*, Pub. Util. Code § 1001 *et seq*.

2. SCE's motion to submit late-filed Exhibit 43 should be granted.

3. The Commission has authority to specify a "maximum cost determined to be reasonable and prudent" for the DPV2 project pursuant to Pub. Util. Code § 1005.5.

4. The Commission should approve a maximum reasonable and prudent cost for this project as specified in Finding of Fact 5.

5. This Commission's determination regarding the maximum reasonable and prudent cost pursuant to § 1005.5 has bearing on the amount of cost recovery SCE may seek from the FERC.

6. If SCE's final detailed engineering design-based construction estimates for the authorized project is one percent or more lower than the authorized maximum cost, SCE should show cause why the Commission should not adopt a lower amount as the maximum reasonable and prudent cost to reflect the final estimate.

7. If SCE's final detailed engineering design-based construction estimates for the authorized project exceeds the authorized maximum cost, SCE should seek an increase in the approved maximum cost pursuant to § 1005.5(b), to allow the Commission to assess whether the cost increases affect the cost effectiveness and need for the DPV2 project.

8. Commission approval of SCE's application, as modified herein, is in the public interest.

9. Project approval should be conditioned upon construction according to the following route:

> In Arizona, the DPV2 project should depart from either the Harquahala Generating Station switchyard or a new Harquahala Junction. If the DPV2 project departs from the Harquahala Generating Station switchyard, it should proceed east, paralleling the existing Harquahala-Hassayampa 500 kV line for approximately five miles to its intersection with SCE's existing DPV1 route at the site of the proposed Harquahala Junction. At this point, whether the route departs from the Harquahala Generating Station switchyard or Harquahala Junction, the route should be the same.
>
> At its intersection with DPV1 at Harquahala Junction, the DPV2 route should turn north (paralleling the DPV1 line) for

approximately 2.4 miles to where it should cross I-10, and then proceed 3.7 miles to a point northeast of Burnt Mountain. From there the route should turn west and roughly parallel the north side of I-10 and the Central Arizona Project Canal for approximately 20 miles into La Paz County, then turn southwest, crossing to the south of I-10 and proceeding approximately 5 miles to a point where it meets the El Paso Natural Gas Company (EPNG) pipeline. The route should parallel the EPNG pipeline and DPV1 for approximately 56 miles, across the Ranegras Plain where a series capacitor bank should be constructed and through La Posa Plain. The route may follow or deviate from SCE's proposed route in the Kofa area. The route should cross over Arizona Highway 95 and proceed into the Dome Rock Mountains to the summit of Copper Bottom Pass. The route should turn southwest and descend the western slope of the Dome Rock Mountains to reach the Colorado River.

The route should cross the Colorado River into California and generally follow the DPV1 right of way to SCE's Devers substation. The route should pass into the Palo Verde Valley, five miles south of Blythe, California and should proceed westerly to the top of the Palo Verde Mesa and then turn northwest to a point two miles south of I-10 and five miles southwest of Blythe Airport. At this point, the route should turn west following the DPV1 line to a point five miles east of Desert Center. DPV2 should either follow the DPV1 route for 10.6 miles or the North of Desert Center route for 11.8 miles north of I-10 and Desert Center to avoid the Alligator Rock Area ACEC. On the west side of Alligator Rock ACEC and south of I-10, the route should continue west for another 24 miles, passing a site where a series capacitor should be constructed, to a point in Shavers Valley where it should turn north and cross I-10 about two miles east of the Cactus City Rest Stop. After crossing I-10, the route should continue west-northwest, parallel to the DPV1 line for 46 miles to the Devers substation.

> The route west of the Devers substation should leave Devers in a westerly direction paralleling SCE's existing Devers-Valley No. 1 line for 41.6 miles. The route should cross into the San Bernardino National Forest and the Santa Rosa and San Jacinto Mountains National Monument and parallel the Devers-Valley No. 1 line westerly and southwesterly until it terminates at SCE's Valley substation.

10. SCE should be authorized to terminate the Devers-Harquahala transmission line at Harquahala Junction or, if Harquahala Junction does not receive the needed approvals in Arizona or is otherwise not feasible, at the Harquahala Generating Company switchyard.

11. If the USFWS rejects the proposed route for DPV2 paralleling DPV1 through Kofa, that route will become legally infeasible.

12. SCE should be authorized to construct a route in the Kofa area that is acceptable to the USFWS and other permitting agencies, subject to a showing, if a proposed routing modification causes expected DPV2 costs to exceed the authorized maximum cost, that the routing modification is not detrimental to the cost effectiveness of DPV2.

13. SCE should be authorized to construct the North of Desert Center alternative or, if BLM does not authorize the North of Desert Center alternative, to construct DPV2 on a route segment through the Alligator Rock ACEC that is acceptable to BLM if the route segment received full consideration in the Final EIR/EIS or if it deviates from one of the reviewed segments solely within BLM land.

14. If SCE and IID reach agreement regarding integration of DPV2 and the Desert Southwest transmission project, SCE should be required to address environmental and other impacts of the proposed upgrades to DPV2 if it requests Commission authorization to construct the Midpoint substation or any

other facilities related to integration of DPV2 and the Desert Southwest transmission project.

15. The West of Devers portion of SCE's proposed DPV2 project is not legally feasible.

16. SCE should be authorized to construct the Devers-Valley No. 2 transmission line as part of the DPV2 project.

17. SCE should amend its EMF management plan as needed to apply its no-cost 500 kV EMF management techniques to the Devers-Valley corridor in addition to the Devers-Harquahala corridor, and to incorporate low-cost EMF mitigation as described in Section V.C of this decision.

18. The Commission retains authority to approve SCE's EMF management plan to ensure that it does not create adverse environmental impacts.

19. The mitigation measures contained in Attachment A to this decision should be adopted and made conditions of project approval.

20. The Mitigation Monitoring, Compliance, and Reporting Plan in Section X of Attachment B to this decision should be adopted.

21. The findings required by CEQA Guidelines Section 15091, as contained in Attachment B to this decision, should be adopted.

22. The Final EIR/EIS has been completed in compliance with the CEQA guidelines.

23. Section H.1.3 in the Final EIR/EIS should be deleted.

24. With deletion of H.1.3, the Final EIR/EIS satisfies CEQA requirements and should be certified.

25. Pub. Util. Code § 625(a)(l)(A) does not apply to this project. However, SCE must provide notice pursuant to § 625(a)(l)(B) if and when it pursues installation of facilities for purposes of providing competitive services.

26. SCE's motion regarding reimbursement of DRA consultant expenses should be denied, except that SCE should be required to pay all outstanding invoices for DRA consultant expenses expeditiously.

27. This order should be effective today so that SCE may proceed expeditiously with construction of the authorized project.

O R D E R

IT IS ORDERED that:

1. A Certificate of Public Convenience and Necessity (CPCN) is granted, subject to the conditions set forth in this Order, to Southern California Edison Company (SCE) to construct a 500 kilovolt (kV) transmission line between either the Harquahala Generating Station switchyard or a new Harquahala Junction in Arizona to SCE's Devers substation, a 500 kV transmission line between the Devers substation and SCE's Valley substation, and associated facilities (collectively, the Devers-Palo Verde No. 2 (DPV2) project).

2. SCE shall, as a condition of the CPCN, build the DPV2 project in accordance with the following route:

> In Arizona, the DPV2 project shall depart from either the Harquahala Generating Station switchyard or a new Harquahala Junction. If the DPV2 project departs from the Harquahala Generating Station switchyard, it shall proceed east, paralleling the existing Harquahala-Hassayampa 500 kV line for approximately five miles to its intersection with SCE's existing Devers-Palo Verde No. 1 (DPV1) route at the site of the proposed Harquahala Junction. At this point, whether the route departs from the Harquahala Generating Station switchyard or Harquahala Junction, the route shall be the same.

At its intersection with DPV1 at Harquahala Junction, the DPV2 route shall turn north (paralleling the DPV1 line) for approximately 2.4 miles to where it shall cross Interstate 10 (I-10), and then proceed 3.7 miles to a point northeast of Burnt Mountain. From there the route shall turn west and roughly parallel the north side of I-10 and the Central Arizona Project Canal for approximately 20 miles into La Paz County, then turn southwest, crossing to the south of I-10 and proceeding approximately 5 miles to a point where it meets the El Paso Natural Gas Company (EPNG) pipeline. The route shall parallel the EPNG pipeline and DPV1 for approximately 56 miles, across the Ranegras Plain where a series capacitor bank shall be constructed and through La Posa Plain. The route may follow or deviate from SCE's proposed route in the Kofa National Wildlife Reserve (Kofa) area. The route shall cross over Arizona Highway 95 and proceed into the Dome Rock Mountains to the summit of Copper Bottom Pass. The route shall turn southwest and descend the western slope of the Dome Rock Mountains to reach the Colorado River.

The route shall cross the Colorado River into California and generally follow the DPV1 right of way to SCE's Devers substation. The route shall pass into the Palo Verde Valley, five miles south of Blythe, California and shall proceed westerly to the top of the Palo Verde Mesa and then turn northwest to a point two miles south of I-10 and five miles southwest of Blythe Airport. At this point, the route shall turn west following the DPV1 line to a point five miles east of Desert Center. DPV2 shall either follow the DPV1 route for 10.6 miles or the North of Desert Center route for 11.8 miles north of I-10 and Desert Center to avoid the Alligator Rock Area of Critical Environmental Concern (ACEC). On the west side of Alligator Rock ACEC and south of I-10, the route shall continue west for another 24 miles, passing a site where a series capacitor shall be constructed, to a point in Shavers Valley where it shall turn north and cross I-10 about two miles east of the Cactus City Rest Stop. After crossing I-10, the route shall continue west-northwest, parallel to the DPV1 line for 46 miles to the Devers substation.

> The route west of the Devers substation shall leave Devers in a westerly direction paralleling SCE's existing Devers-Valley No. 1 line for 41.6 miles. The route shall cross into the San Bernardino National Forest and the Santa Rosa and San Jacinto Mountains National Monument and parallel the Devers-Valley No. 1 line westerly and southwesterly until it terminates at SCE's Valley substation.

3. SCE shall pursue good-faith efforts to reach a commercially reasonable agreement and seek the additional authorizations needed for construction of Harquahala Junction. SCE is authorized to terminate the Devers-Harquahala transmission line at Harquahala Junction or, if Harquahala Junction does not receive the needed approvals in Arizona or is otherwise not feasible, at the Harquahala Generating Company switchyard.

4. Official notice is taken that the United States Fish and Wildlife Service (USFWS) has issued a preliminary Determination of Incompatibility regarding construction of DPV2 through Kofa as proposed by SCE.

5. SCE is authorized to construct a route in the Kofa area that is acceptable to the USFWS and other permitting agencies, subject to a showing, if a proposed routing modification causes expected DPV2 costs to exceed the maximum cost adopted in this Order, that the routing modification is not detrimental to the cost effectiveness of DPV2.

6. SCE is authorized to construct the North of Desert Center alternative or, if the United States Department of Interior, Bureau of Land Management (BLM) does not authorize the North of Desert Center alternative, to construct DPV2 on a route segment through the Alligator Rock ACEC that is acceptable to BLM if the route segment received full consideration in the Final Environmental Impact Report/Environmental Impact Statement (Final EIR/EIS) for DPV2 or if it deviates from one of the reviewed segments solely within BLM land.

7. If SCE requests Commission authorization to construct the Midpoint substation or any other facilities related to integration of DPV2 and the Desert Southwest transmission project, SCE shall address environmental and other impacts of upgrades to DPV2 that would be undertaken to integrate DPV2 and the Desert Southwest transmission project.

8. SCE is authorized to construct the Devers-Valley No. 2 transmission line as part of the DPV2 project.

9. SCE shall, as a condition of the CPCN, design and construct DPV2 to increase the transfer capability between southern California and Arizona by at least 1,200 megawatts (MW) and shall turn over at least 1,200 MW of transfer capability to the California Independent System Operator (CAISO).

10. Pursuant to Pub. Util. Code § 1005.5(a), the maximum cost determined to be reasonable and prudent for the DPV2 project, including pension and benefits, and administrative and general expenses, but excluding Allowance for Funds Used During Construction, is $545,285,000 in 2005 dollars, to be decreased by $24,080,000 if the Devers-Harquahala line is terminated at Harquahala Junction and increased by $8,282,000 if the Alligator Rock—North of Desert Center route segment is used. The Handy-Whitman Index of Public Utility Construction Costs shall be used in assessing compliance with the authorized maximum cost.

11. Once SCE has developed a final detailed engineering design-based construction estimate for the final route, if this estimate is one percent or more lower than the authorized maximum reasonable and prudent cost identified in Conclusion of Law 10, SCE shall, within 30 days, file an advice letter to show cause why the Commission should not adopt a lower amount as the maximum reasonable and prudent cost to reflect the final estimate.

12. If SCE's final detailed engineering design-based construction estimate for the authorized project exceeds the authorized maximum cost, SCE shall, within 30 days, file an advice letter to seek an increase in the approved maximum cost pursuant to § 1005.5(b), and shall address whether the cost increases affect the cost effectiveness and need for the DPV2 project.

13. As low-cost electric and magnetic field (EMF) mitigation, SCE shall increase tower and conductor heights by 20 feet along those portions of the DPV2 transmission corridor where there are residential properties within 50 feet of the side of the right of way closer to the DPV2 line. SCE shall apply this low-cost EMF mitigation where there are existing residential properties and where development of new residences is underway at the time SCE undertakes final DPV2 project design.

14. SCE shall amend its EMF management plan to apply its no-cost 500 kV EMF management techniques to the Devers-Valley corridor in addition to the Devers-Harquahala corridor, and to incorporate the low-cost EMF mitigation adopted in Ordering Paragraph 13.

15. SCE shall, as a condition of the CPCN, build the DPV2 project in accordance with its EMF management plan as modified consistent Ordering Paragraph 14.

16. SCE shall, prior to commencing construction, submit a detailed EMF management plan for approval of the Commission's Energy Division. The plan shall describe in detail each mitigation element, the cost of each element, and the percentage by which that mitigation will reduce EMF levels.

17. The mitigation measures contained in Attachment A to this decision are adopted.

18. The mitigation monitoring and reporting program contained in Section X of Attachment B to this decision is adopted.

19. SCE shall, as a condition of the CPCN, comply with all applicable mitigation measures specified in Attachment A attached hereto, as directed by the Commission's Executive Director or his designee(s). SCE shall work with the Commission's Energy Division to create detailed maps for use in construction and mitigation monitoring.

20. The Executive Director shall supervise and oversee construction of the project insofar as it relates to monitoring and enforcement of the adopted mitigation measures contained in Attachment A to this decision. The Executive Director may delegate these duties to one or more Commission staff members or outside staff. The Executive Director is authorized to employ staff independent of the Commission staff to carry out such functions, including, without limitation, the on-site environmental inspection, environmental monitoring, and environmental mitigation supervision of the construction of the project. Such staff may be individually qualified professional environmental monitors or may be employed by one or more firms or organizations. In monitoring the implementation of the adopted mitigation measures, the Executive Director shall attribute the acts and omissions of SCE's employees, contractors, subcontractors, or other agents to SCE. SCE shall comply with all orders and directives of the Executive Director concerning implementation of the adopted mitigation measures.

21. The findings required by California Environmental Quality Act (CEQA) Guidelines Section 15091, as contained in Attachment B to this decision, are adopted.

22. Section H.1.3 in the Final EIR/EIS is deleted.

23. With deletion of Section H.1.3, the Final EIR/EIS for the DPV2 project is certified pursuant to CEQA.

24. The Commission finds that the DPV2 project will provide substantial benefits, in that it will provide significant economic benefits for CAISO-area ratepayers, increase the reliability of the interstate transmission network, increase operational flexibility, and provide insurance value as an economic hedge against low-probability, high-impact events. The Commission finds that the DPV2 project's unavoidable impacts are acceptable in light of these substantial benefits, which constitute an overriding consideration warranting approval of the project, despite each and every unavoidable impact.

25. SCE shall file a written notice with the Commission, served on all parties to this proceeding, of its agreement, executed by an officer of SCE duly authorized (as evidenced by a resolution of its board of directors duly authenticated by a secretary or assistant secretary of SCE) to acknowledge SCE's acceptance of the conditions set forth in the Ordering Paragraphs of this decision. Failure to file such notice within 75 days of the effective date of this decision shall result in the lapse of the authority granted by this decision.

26. The Executive Director shall file a Notice of Determination for the project as required by CEQA and the regulations promulgated pursuant thereto.

27. Upon satisfactory completion of the project, SCE shall file a notice of completion with the Executive Director by the Energy Division.

28. SCE's right to construct the DPV2 project as set forth in this decision shall be subject to all other necessary federal, State and local permitting processes and approvals.

29. SCE's motion to submit late-filed Exhibit 43 is granted.

30. SCE shall pay all outstanding invoices for Division of Ratepayer Advocates (DRA) consultant expenses within five days of the effective date of this order. In all other respects, SCE's motion regarding reimbursement of DRA consultant expenses is denied.

31. Application 05-04-015 is closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list (see Attachment C).

Upon confirmation of this document's acceptance for filing, I will cause a copy of the Notice of Availability to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the copy of the filed document Notice of Availability is current as of today's date.

Dated December 22, 2006, at San Francisco, California.

/s/ FANNIE SID

Fannie Sid